Application

Transmission Network
Revenue Cap
Commencing January 2002

February 2001

Powerlink Queensland

Table of Contents

Application for Transmission Network Revenue Cap

1 Abbreviations

Abbreviation	Definition
ACCC	Australian Competition and Consumer Commission
ACEA	Australian Consulting Engineers Association
Application	This document, being Powerlink's formal application to the ACCC for determination of its revenue caps from 1 January 2002
APS	Powerlink Queensland's Annual Planning Statement
ASX	Australian Stock Exchange
Capex	Capital expenditure which is part of the revenue building block
CAPM	Capital Asset Pricing Model
CPI	Consumer Price Index
DAC	Depreciated Actual Cost
DNSP	Distribution Network Service Provider
DRP	ACCC's Draft Statement of Regulatory Principles
ERU	Electricity Reform Unit – the Queensland Interim Regulator
FDC	Financing costs During Construction
IDC	Interest During Construction (often used to refer to FDC)
NEC	National Electricity Code
NECA	National Electricity Code Administrator Limited
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company Limited
NIEIR	National Institute of Economic and Industrial Research
ODRC	Optimised Depreciated Replacement Cost
ORV	Optimised Replacement Value
ORG	Office of the Regulator-General
Powerlink	Queensland Electricity Transmission Corporation Ltd trading as Powerlink Queensland
QCA	Queensland Competition Authority
QNI	Queensland – New South Wales Interconnector
RAB	Regulated Asset Base
SAP	Powerlink's Integrated ERP (Enterprise Resource Planning) Business System
SLA	Service Level Agreement
SMHEA	Snowy Mountains Hydro-Electric Authority
TNSP	Transmission Network Service Provider
TUOS	Transmission Use of System charge
WACC	Weighted Average Cost of Capital

2 Requirement for Determination

2.1 Regulation Commencement Date

The ACCC is required to administer Powerlink's regulated revenue from 1 January 2002, this date being the *transmission regulation commencement date* for Queensland (NEC Clause 9.38.1 (c)).

2.2 Statement of Regulatory Principles

As national regulator for transmission, the ACCC has, on the 27 May 1999, released its "Draft Statement of Principles for the Regulation of Transmission Revenues" – the DRP. This document sets out the principles the ACCC will use to determine a TNSP's maximum allowable revenues under Chapter 6B of the NEC. The ACCC has already demonstrated its implementation and application of these principles in its regulatory determination of revenues for other TNSPs including TransGrid and SMHEA.

To the maximum extent possible, this Application is consistent with the principles of the DRP, and the demonstrated practical application of those principles by the ACCC to other TNSPs. It is noted that the ACCC's statement of regulatory principles is still in its draft form, with a number of principles not yet fully developed.

In some instances where the principles appear incomplete, Powerlink has consulted with the ACCC prior to this Application with a view to clarifying an approach which best reflects the circumstances of the Queensland region of the NEM, and which best meets the needs of the ACCC in terms of allowing it to undertake its obligations.

Where further clarification of the interpretation of the DRP is required during this process, Powerlink requests that the ACCC provide Powerlink with the opportunity to participate in order that the specific circumstances of the Queensland power system can be taken into account.

2.3 The Application

Principle S2.1 of the DRP requires the TNSP to submit a formal application at least eight months prior to the expiry of the current regulatory period. This principle requires that this application must include sufficient information to support its case for maximum allowable revenues for the forthcoming regulatory period.

In line with this requirement, Powerlink hereby makes its formal Application dated 14 February 2001.

2.4 Regulatory Control Period

Clause 6.2.4 of the NEC requires that the regulatory control period is to be for a period of not less than 5 years, however Clause 9.38.2 of the NEC reduces this period to not less than 3 years in the case of Queensland. Notwithstanding this transitional provision, Powerlink requests, in this Application, that a nominal regulatory control period of 5 years apply. The commencement date for this regulatory period is 1 January 2002 which requires the period to extend to at least 31 December 2006.

Powerlink requests the ACCC align each regulatory year of the regulatory control period with full financial years ending 30th June. Such alignment will simplify, and provide consistency with, reporting and forecasting processes, and will minimise the cost impact of the regulatory process. Accordingly, it is requested that the regulatory control period extend to 30 June 2007, as detailed in the table below.

Table 2.1. Regulatory Control Period

	January 2002 – June 2002	July 2002 – June 2003	July 2003 – June 2004	July 2004 – June 2005	July 2005 – June 2006	July 2006 – June 2007
Reg. Year	Transition	1	2	3	4	5
Duration	6 months	1 year	1 year	1 year	1 year	1 year

Such a regulatory control period would extend for 5½ years, with the first six month period representing a transition period, recognising that the Queensland interim regulator (ERU) has already met its obligation for setting revenue caps up to 31 December 2001. In so doing, ERU determined the revenue cap on a full year basis (ie for the 2001/2002 year, ending June 2002).

For completeness and consistency, Powerlink will provide data for the 2001/2002 year on a full year basis.

The ACCC therefore has two alternative approaches which it could apply to cover the half year period 1 January, 2002 to 30 June, 2002:

- The revenue cap set by ERU for the 2001/02 year will be pro-rated (i.e. 184 out of 365 days) and applied to the period July 2001-December 2001, and the ACCC could determine a new revenue cap for January 2002-June 2002 period; or

- Notwithstanding the revenue caps resulting from this regulatory assessment, ACCC could decide to simply apply the ERU-determined revenue cap to the whole of 2001/02.

The latter approach provides a benefit to Queensland customers as it would avoid a mid-year adjustment to both transmission prices and potentially distribution prices (which are computed from the transmission prices).

On the other hand, Powerlink believes that the revenue caps set by ERU were “sub-economic” – that is, they did not reflect the full risks and costs of the business. ERU also set the revenues for the two Queensland distribution networks at the same time. In its recent draft determination of those distribution entities for the period commencing 2001/02, Queensland’s new independent regulator (QCA) recognised the “sub-economic” settings by ERU.

2.5 Transmission Prices

This Application pertains to seeking a determination by the ACCC of Powerlink’s regulated revenue caps for the period 1 January 2002 to 30 June 2007. Powerlink will subsequently, as a separate annual process, convert the revenue caps into transmission prices, in accordance with the provisions of the NEC.

3 Powerlink – Business Characteristics

3.1 Introduction

Powerlink believes that this submission demonstrates that Powerlink is the most efficient transmission entity in the National Electricity Market, and one of the most efficient stand-alone transmission entities in the world.

Fundamental to understanding the efficiency of electricity transmission networks is the recognition that electricity transmission is a TRANSPORTATION activity. The cost drivers for electricity transmission are derivatives of those for any transportation activity.

3.2 Powerlink's role

The Queensland Electricity Transmission Corporation Limited, trading as Powerlink Queensland, is a Government owned (Corporations Law) Corporation reporting to its Shareholding Ministers, via a Board of Directors. Powerlink is the sole holder of the transmission authority which authorises it, under the Queensland Electricity Act, to operate the high voltage transmission grid in Queensland.

The transmission authority obligates Powerlink to comply with the National Electricity Law as well as comply with the Electricity Act (Queensland) and other relevant legislation. These laws require that Powerlink develop, operate, maintain and protect its transmission grid to ensure the adequate, economic, reliable and safe transmission of electricity. In addition, it requires that the transmission grid is operated, augmented or extended to provide sufficient capacity so as to ensure network services are available to persons authorised to access the grid.

3.3 The Queensland transmission "grid" - a classic case of geography driving costs

Powerlink owns and operates one of the longest (and "skinniest") high voltage transmission grids in the world, stretching more than 1700 km from Cairns in the Far North to the New South Wales border in the south. The Queensland – NSW

Interconnector (QNI) has just been completed and connects the Queensland transmission grid to the remainder of the National Electricity Grid.

The transmission distances in Queensland are very long by world standards, and are by far the longest in the NEM. This is THE most significant driver on Powerlink’s costs.

The length and service of the Powerlink grid is shown in Figure 3.1.

Another feature of the Queensland network evident from the map is that most of Powerlink’s recent transmission augmentations (eg Qld /NSW Interconnector , new Central Queensland – Southern Queensland lines) are located hundreds of kilometres to the west of the existing infrastructure. As a result, Powerlink’s infrastructure is expanding into locations much more distant from the established maintenance depots and service facilities. This results in higher maintenance costs to deliver a service standard consistent with the rest of the network.

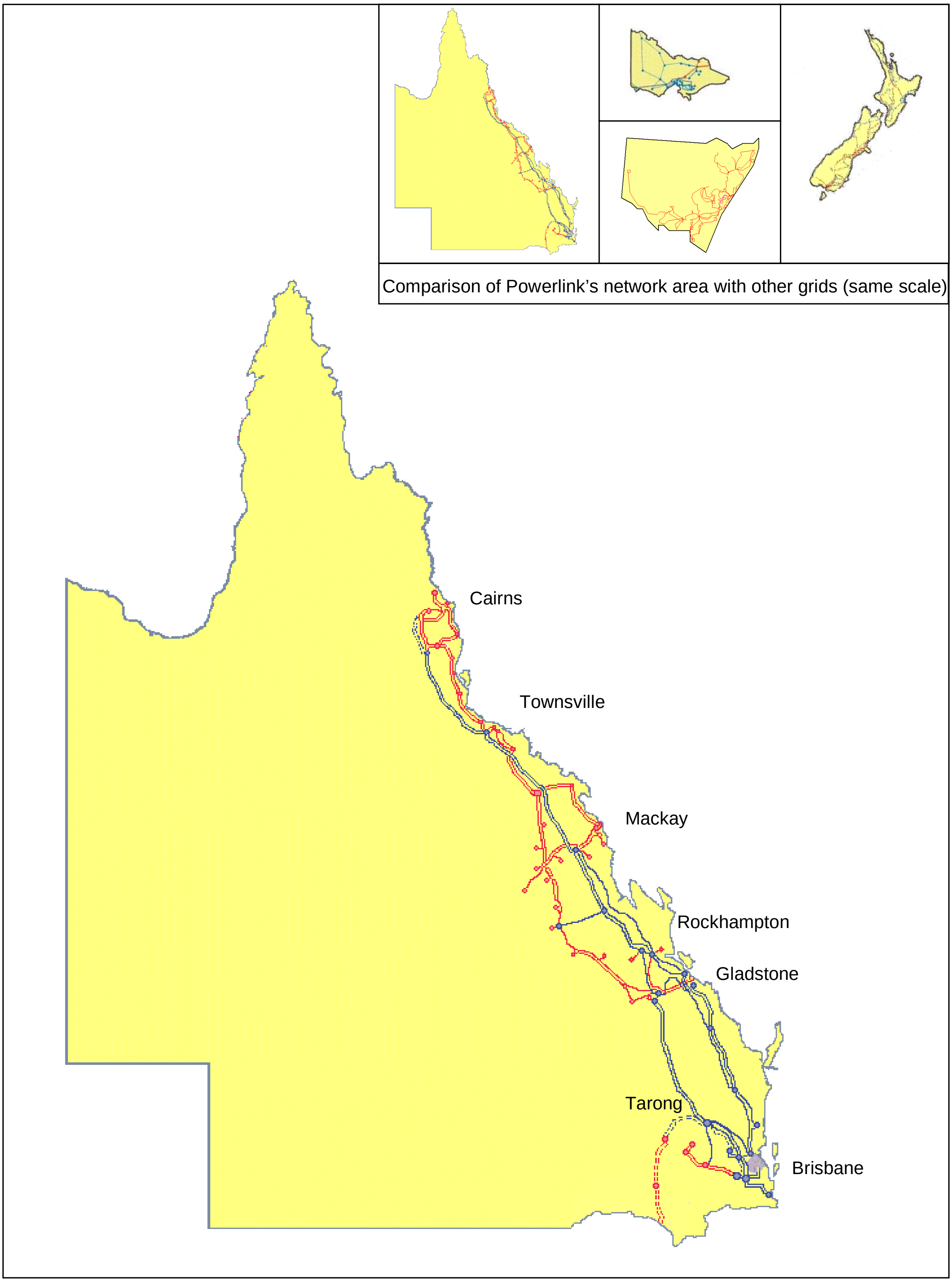


Figure 3.1. Powerlink's Transmission System

3.4 Customers

Powerlink's customers comprise generators, distributors and direct connect major loads (eg smelters) as shown in Table 3.1 below.

Table 3.1. Powerlink's customers

Customer Type	No. of Customers	No. of Connection locations	No. of Connection points
Generators	11	20	69
Distributors	3	66	205
Direct Connect Loads	3	3	10

Queensland is the most decentralised of all Australian states and this means that its transmission grid has to be capable of transmitting relatively larger quantities of power over longer distances, to supply the major regional centres and provincial cities and remote industries.

Queensland's major generation sources are located in Central Queensland and the Surat Basin necessitating large amounts of power to be transmitted over very long distances (500km to 1,000km) to the growing load centres in the state. In other states, the major power generating stations are located significantly closer (typically 150km to 200km) to the major load centres. Thus the transportation task in Queensland is much greater than in other Australian States.

Transportation of high quantities of power over long distances creates high reactive loadings on the grid which presents additional challenges in terms of voltage control, particularly during contingency events. This problem, solved by increasing the network capacity and by installing static voltage control plant, is further exacerbated by the unique characteristic of Queensland's high and constant air conditioning load through the summer months.

3.5 Supply and Demand - A heavily loaded grid , with high demand growth

The Queensland transmission grid operated by Powerlink supplied a maximum demand for electricity of 6,584 MW over the 2000/01 summer peak. Under extreme weather conditions this demand could increase by almost 200 MW. Because of the constant hot and humid climate in Queensland, the peak summer demand occurs for the entire summer period, rather than for a few days as occurs in the southern States.

The daily load profile, as shown in Figure 3.2, shows that the daily demand exceeds 80% of the peak demand for 16 hours per day in both summer and winter. The average loading on the grid throughout the entire year is about 80% of the peak loading, which is by far the highest in Australia, and very high by world standards (which are typically in the range 50% - 60%). The very flat daily load curve in Queensland is partly due to the already high amount of demand side management and leaves little scope for additional demand management to be used to defer grid augmentation.

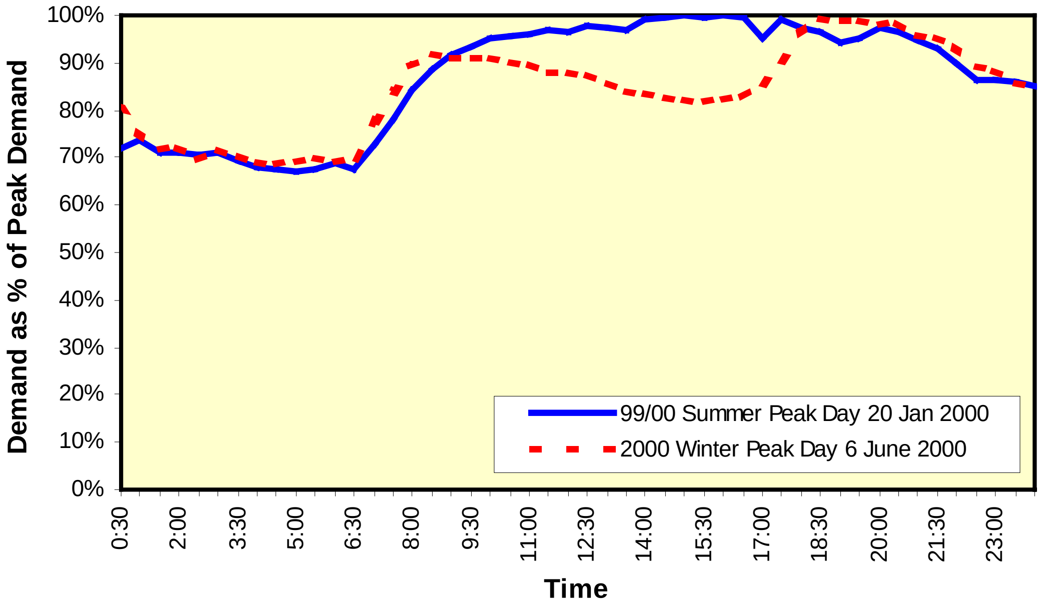


Figure 3.2. Daily load profile for the 1999/2000 summer peak day and the 2000 winter peak day

The high annual duration of loading is shown, and compared with other States, in Figure 3.3. In Queensland the demand exceeds 80% of the peak annual demand for 45% of the time whereas the corresponding statistic for the other States is only 4% to 7%. This means that the Queensland grid is exposed to very high loads for almost 10 times as long as other networks. As a result there is a much greater probability that outages of the network will result in load shedding and constraints. This demands a higher level of availability from the components of the Queensland grid to achieve the same standard of service, which means inherently more investment in grid components and increased maintenance requirements.

Maintenance costs are driven up as there are far fewer opportunities within such a heavily loaded grid to schedule maintenance outages other than at weekends or overnights (with consequential higher overtime costs for labour).

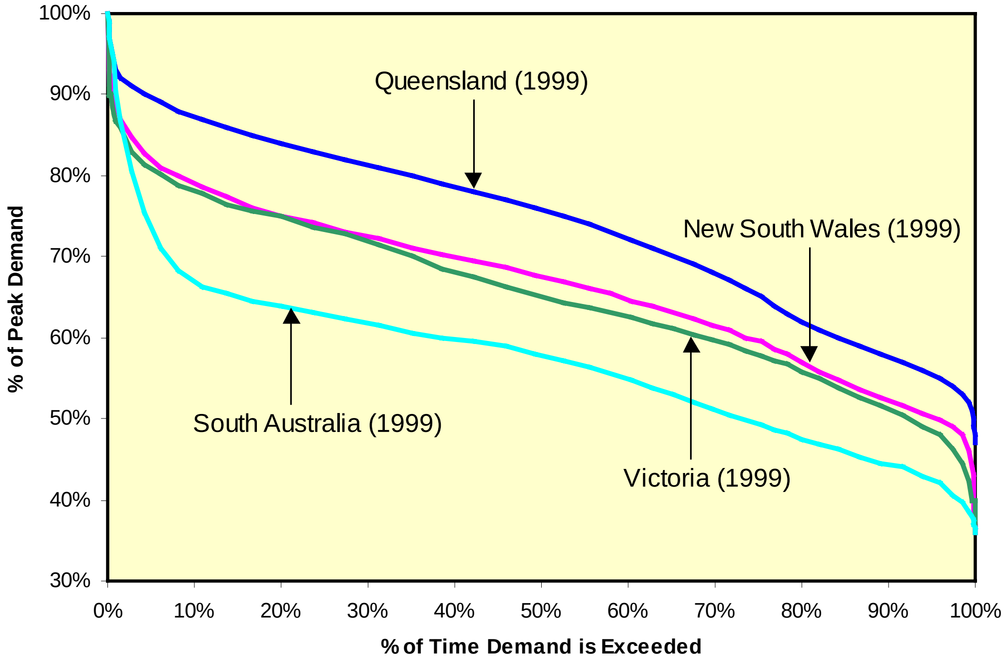


Figure 3.3. Cumulative annual load duration curves

Queensland has consistently experienced much higher growth in electricity demand than other States due to its high population growth and regional development. Historical trends are shown in Figure 3.4 below, together with the forecast increase in summer peak demand.

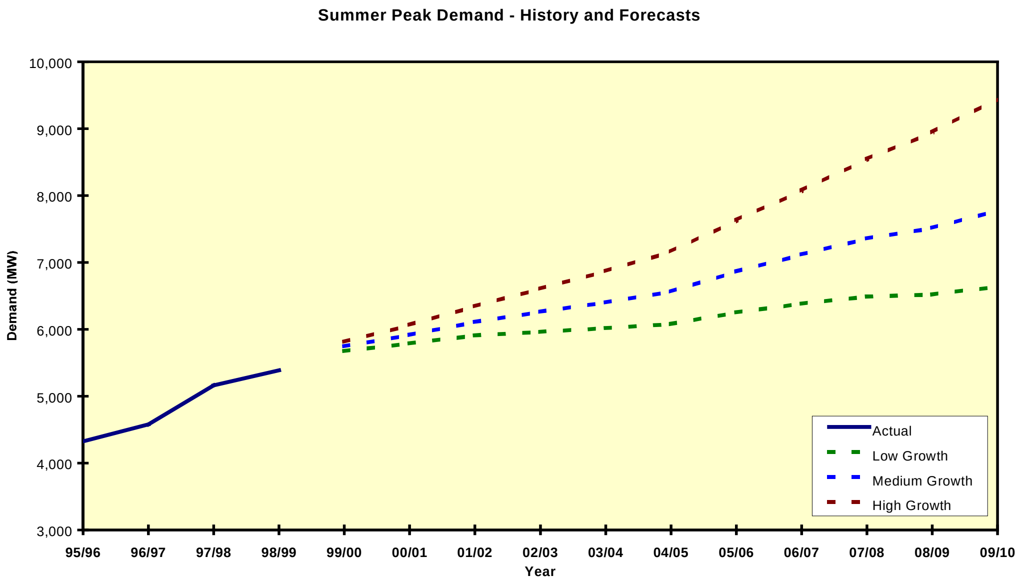


Figure 3.4 Load Forecast

Even after allowing for optimistic increases in embedded generation driven by government policies, demand is forecast to grow by an average of 3.1% per annum over the next 10 years. A detailed load forecast has been conducted by independent consultants and is outlined in Powerlink's 2000 Annual Planning Statement and summarised in Chapter 7 of this Application. The forward projections shown in Figure 3.4 above are based on this independent forecast. This is a high growth rate for such a heavily loaded grid, and drives the forecast capex in this submission. This growth translates into an annual increase of demand of around 220 MW.

3.6 Assets

The Powerlink high voltage transmission network includes in excess of 10,300 circuit kilometres of lines and eighty (80) substations which include 11,813 MW of installed transformer capacity. Powerlink's assets are summarised in Table 3.2 and Table 3.3 below.

Table 3.2. Summary of Powerlink's Transmission Line Assets

Line Voltage	Single Circuit	Double Circuit	Circuit Km
275 kV	3,417	1,204	5,825
132 kV	1,282	1,338	3,958
110 kV	36	244	524
66 kV and below	1	0	1
TOTAL	**4,736**	**2,786**	**10,308**

Table 3.3. Summary of Powerlink's Substation Assets

Highest Voltage	Substations	Circuit Breaker Bays	Transformers	
			Number	MVA
275 kV	23	231	39	7,515
132 kV	46	311	65	3,168
110 kV	11	171	20	1,090
66 kV and below	0	62	4	40
TOTAL	**80**	**775**	**128**	**11,813**

Very high asset utilisation both in terms of the small amount of assets employed and the high loading of these assets is indicative of Powerlink's very efficient use of capital invested in the grid. Powerlink has also achieved very high efficiency with its supporting functions including its network control and administration support facilities. Powerlink operates and maintains a single, central network control centre (consolidated in 2000 from 3 regional control centres) as well as an extensive communications network which provides for the effective, safe and efficient operation of the above transmission assets. Other grids the same size as Powerlink's would typically have multiple control centres.

Powerlink has a single office location combined with a field staff depot at its Virginia complex. The consolidation of the depots and offices in recent years has resulted in considerable ongoing cost savings. Other grids typically have multiple depots and office facilities.

Powerlink's transmission assets date back to the 1950's with a significant component of the asset base being more than 30 years old. These older assets tend to have higher maintenance costs and provision must be made for replacement or refurbishment due to obsolescence and high level of loading. Powerlink's asset age profile is shown in Figure 3.5.

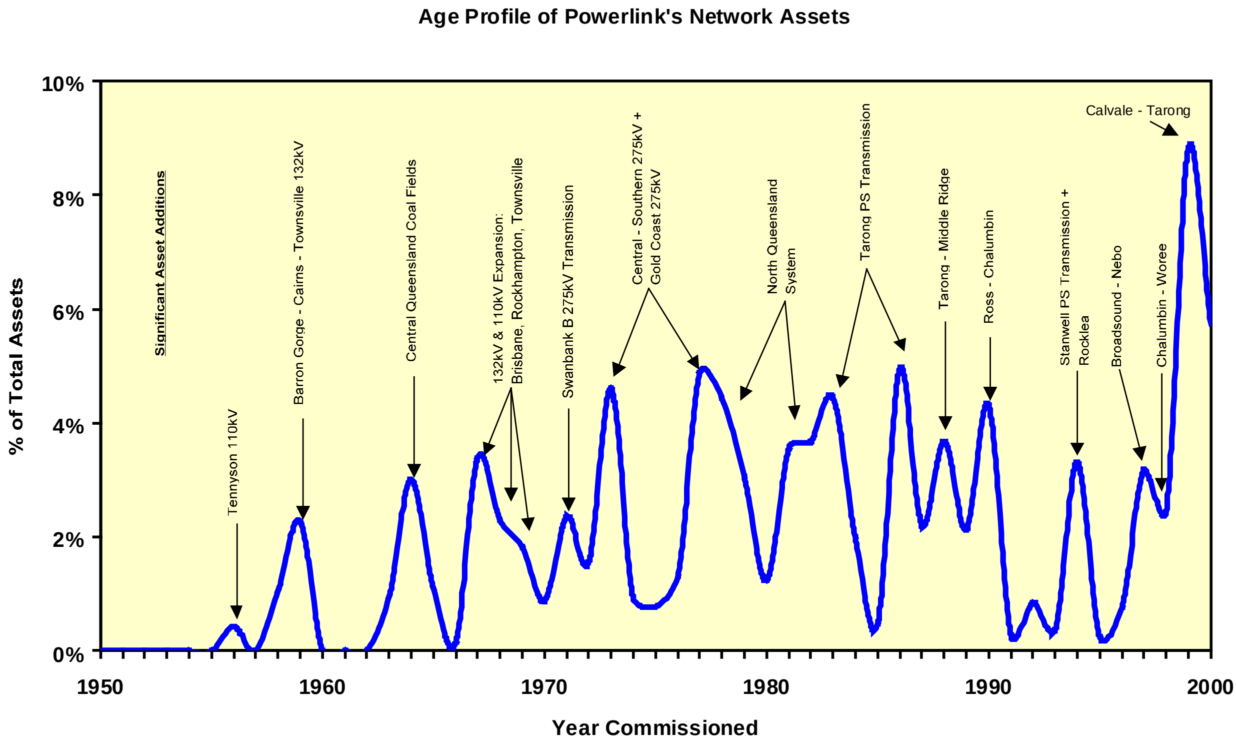


Figure 3.5. Age profile of Powerlink Assets

3.7 Transmission - a Transportation Business

Electricity transmission is fundamentally a transportation business – as such, the economics are driven by not only how much is transported (MW), but also by how far it is transported (km) and by whether the deliveries are made in very large lots or not (load density). The economics are conceptually similar to other bulk transportation businesses e.g. freight railroads.

All of these underlying cost drivers must be taken into account when comparing one transmission business with another. It is economically naive to make comparisons simply on the basis of costs per MW or per MWh, without considering both the haul distance and the load density. For example, comparisons on freight railroads are done on cost per tonne km, to take distance into account, and not cost per tonne.

Similarly, it is inherently more economical to have fewer and larger delivery points (high load density) than a large number of widely spaced, lower load density delivery points such as occurs throughout Queensland (except for the SE corner).

A relevant example in Australian electricity transmission is the comparison between TransGrid (the NSW transmission entity), which the ACCC and its consultants studied in 1999/2000, and Powerlink. The New South Wales grid has an annual maximum demand of 10,900 MW compared to Queensland's maximum demand of 6,600 MW. It would be inappropriate to interpret the ratio of these figures as the comparative size of the transportation task facing the respective transmission entities. One way to get a more economically sound comparison is to consider a measure such as MW-km which is a cumulative measure of the distance each MW needs to be transported from the generators to the customer load points. This measure is independent of the network design and can be considered to be an elementary measure of the transportation task (although it still doesn't account for differences in load density). It is akin to the tonne km measure used by freight railroads.

Powerlink has attempted to develop a measure of MW-kms for both grids from public domain information such as power flow outputs from Annual Planning Statements, with distances scaled from maps, as shown in Figure 3.6. Admittedly, these measures are approximate.

Our calculations indicate that while the New South Wales grid has a cumulative haulage of 2,060,000 MW-km, the Queensland grid is required to transport some 1,850,000 MW-km, a haulage task of 90% of that of the New South Wales grid.

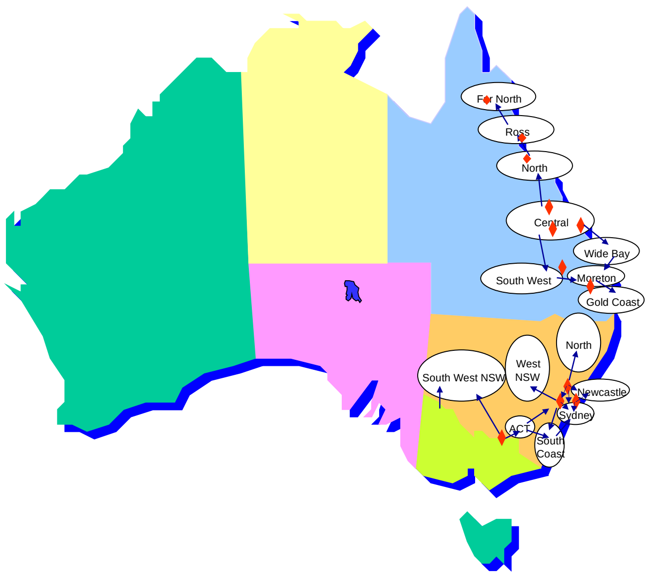


Figure 3.6. The transportation task for Queensland and New South Wales

A further factor to be considered is the economies of scale of transmission, which come with the transmission of larger blocks of power to more densely populated areas. As the load densities in Qld are lower than in NSW, this further adds to the transportation task for electricity transmission in Qld compared with the size of the task for the NSW transmission entity.

It is therefore perhaps not surprising that independent, "bottom-up" valuations of the transmission assets in each State – using ACCC principles and approaches – indicate that the optimal value of the transmission assets in both states are similar, consistent with the relative size of the transportation tasks.

It therefore costs more to transport each MW or MWh (but not each MW-km) in Queensland than in NSW.

3.8 Operating Cost efficiency – a Powerlink strength

Powerlink's total controllable operating costs are only 2.4% of the transmission network asset value (ODRC basis). By comparison, the same measure for 5 other transmission entities in Australia and NZ (based on data obtained largely from Annual Reports) ranges from 3.1% to 6.2%, averaging 4.5%. International benchmarking shows that the Powerlink value of 2.4% is low by international standards.

These low operating costs reflect the efficiency measures that have already been implemented in the Powerlink business and confirm that Powerlink is already setting the efficiency standard for transmission entities in the Australia / NZ region and internationally.

Clearly there is a linkage between operating costs and service standards – delivering a higher service standard would necessitate increased operating and capital expenditure. These issues are considered elsewhere in Powerlink's submission.

3.9 Excluded Services

The majority (94%) of Powerlink's revenues come from operating the shared transmission network in Queensland, and are therefore regulated. However, Powerlink earns a small amount of revenue from non-regulated activities:

- network activities (2%) – eg. the provision and operation of contestable network connection assets between new power stations and new major loads (post 1995), and the shared grid;

- non-network activities (4%) – eg. technical consulting services such as oil analysis, and engineering consulting.

Powerlink has put systems in place which enable the separation of regulated assets and activities from non-regulated assets and activities **at source**, and thus provide for separate recording and reporting of assets, revenues and expenditures.

This Application for determination of revenue caps by the ACCC is confined to Powerlink's regulated activities. **All assets, costs and revenues associated with non-regulated (excluded) activities have been kept separate from the regulated activities.**

It should be noted that Powerlink's minority equity interest in ElectraNet SA is controlled through subsidiaries which are separate from Powerlink's regulated activities and, therefore, not considered further in this Application.

4 The Cost of Capital

4.1 Introduction

Given the capital intensive nature of electricity networks, the return on capital component of regulated revenue accounts for a significant portion of the annual aggregate revenue.

Setting a rate below the risk-weighted cost of funds in the market would make continued investment in developing the network unattractive for the network owner, which would inevitably lead to a degradation in network security, reliability and quality of supply. It would also destroy rather than encourage the potential for competition, by making it unprofitable for rival suppliers to emerge.

There are many parallels between Powerlink's business, other electricity transmission businesses recently assessed by the ACCC, and other electricity networks recently examined by jurisdictional regulators. However, there is also a *very significant difference* – **Powerlink's regulated network business faces materially higher levels of risk**, due to the following factors which are not present in other networks to the same extent as in Queensland:

- ❖ Much higher loading of the Queensland network;
- ❖ Greater uncertainty in future customer load growth;
- ❖ Uncertain future generating patterns arising from the impacts of committed new generating plant and the wide range of possible uncommitted generating developments;
- ❖ Impacts of Queensland's new Energy Policy including competition from gas; and
- ❖ Greater impacts of the 2% Renewable Energy Policy in Queensland.

The Powerlink network operates at much higher relative loadings than other transmission networks due to the very high daily and annual load factors of Queensland (ie exceed 80% annually). This substantially increases the likelihood that network owner may face unforeseen liabilities if unpredictable network outages cause market constraints and/or load shedding.

Queensland faces greater uncertainty in forecasting future load growth than other states due to Queensland's less diverse economy and its higher inherent load growth. Due to the absence of experience with QNI, it is impossible to predict whether QNI will add to the local load growth by exporting power to NSW or the reverse will occur.

During the next three years there will be 2,500 MW of new base load generating capacity connecting to the Powerlink network (ie Callide C, Millmerran, Swanbank E and Tarong North) in addition to QNI which could import 500MW or export 1,000MW. In addition there are proposals for a base load power station in North Queensland and another major power station at Kogan. These developments will have a very large, but unpredictable impact on the dispatch of the existing Queensland power stations and the loading of Powerlink's interconnected transmission network. If for example, the new power stations are bid and operated ahead of the existing 3,000MW of Central Queensland generation which uses higher cost rail-freighted coal, there could be a substantial reduction in the loading of the CQ-NQ and CQ-SEQ transmission systems. This is a significant asset stranding risk that is not present in other Australian States where no new base load power stations are being developed.

The very uncertain future generating pattern in Queensland is illustrated by the finding of an independent consultant who identified 72 plausible scenarios over the coming 5 years. In a recent report for the Interim Queensland Regulator (ERU), Arthur Anderson concluded:

> *"There is a significant risk of asset re-optimisation of Powerlink's assets due to the uncertain nature of new generation projects, possibility of embedded generation and changing fuel market dynamics."*

An additional major risk that is present in Queensland is the current proposal, supported by the Queensland Energy Policy, for the development of a gas pipeline <u>running in parallel with</u> the existing transmission grid and the development of gas fired local generation at the major load centres currently reliant on transmitted electricity. Attachment 1 shows how the existing gas pipelines in Queensland have pathways which complement the electricity transmission grid, whereas the proposed new pipeline runs largely in parallel with the grid and <u>in direct competition</u> with it, creating a significant new asset stranding risk.

The Federal Government's 2% renewable energy policy combined with the proposed Code changes for the payment of avoided TUOS to embedded generators, will increase the risk of asset stranding in Queensland, relative to other states. One of the most likely renewable energy resources to be developed on a large scale as a result of this policy is biomass using waste bagasse from the sugar industry. The Australian Cogeneration Association has estimated that there could be an additional 700MW to 1,000MW of new co-generation capacity developed in the sugar industry as a result. Virtually all of this new capacity would be located in Queensland and would reduce the loading on the existing transmission grid and increase asset stranding risk.

Whilst Powerlink has made provision for the emergence of such cogeneration in its load forecasts, it is not possible to predict the impact on the peak loading of the grid and whether assets could be optimised out, due to the uncertainty in the timing of development, and whether it will generate over the peak summer load periods or only during the cane crushing season. In nearly all cases, Powerlink does not have a direct contractual relationship with the sugar mills (as they connect to the distribution network) and the proponents are reluctant to disclose their development plans due to the competitive nature of the market.

The ACCC's depreciation principles will be ineffective in enabling Powerlink to mitigate its risks in the above circumstances, because the stranding risk will arise quickly and the specific at-risk assets cannot be identified in advance at this regulatory reset.

It is clear that these risks are much larger than for other recently assessed transmission and distribution networks. On that basis, <u>the WACC for Powerlink needs to be significantly higher than for other networks.</u>

4.2 Post-Tax Framework

Until recently, the return on capital calculation for regulated networks in Australia was consistently based on a rate of return that was defined as a pre-tax real weighted average cost of capital (WACC). Powerlink notes, with some concerns, the ACCC’s preference for a post-tax nominal WACC framework.

In our opinion, the post-tax WACC framework fails the crucial test of an effective incentive regulation regime on two key grounds:

- it minimises revenue / prices by regulating profit rather than harnessing the positive incentives for the business to achieve productivity gains; and
- it involves a high degree of regulatory intrusion and scrutiny over business costs which reduces the degree of flexibility available for the business to conduct its operations.

A significant implication of the regulatory approach to quantifying tax under the post-tax WACC framework is that regulated businesses are effectively denied the right to retain the benefits of tax concessions provided by the Government to stimulate productive investment (e.g. research and development, investment and accelerated depreciation). As Dr Alan Moran of the Institute of Public Affairs has pointed out in a submission to the ORG[1], this approach is likely to lead to a reduction in productivity gains and the misallocation of resources over the longer term.

The post-tax WACC framework produces rate of return outcomes that, in our view, are unacceptably low. Long term dynamic efficiency gains are sacrificed for short term productive efficiency gains, and competition is impeded rather than enhanced. In this regard, we consider that the post-tax WACC framework produces outcomes that contradict the provisions of the NEC which require an environment that fosters an efficient level of investment and the promotion of competition.

The appropriate rate of return for regulated utilities should reflect a prospective view of what the business requires to attract capital. We believe that under incentive regulation, the rate of return should have two primary aims:

- to deliver some immediate benefit to customers over the level of prices that would have applied in the absence of incentive regulation; and
- to encourage the regulated business to make further productivity gains that can benefit customers in subsequent price sets.

[1] Submission to the ORG: The Appropriate Treatment of Company Taxation in Determining a Revenue Cap for a Regulated Business, Energy Issues Paper No. 14, April 2000, by Dr. Alan Moran, Director, Deregulation Unit, Institute of Public Affairs Ltd.

Powerlink recommends application of the pre-tax method. However, we note that the Draft Statement of Regulatory Principles endorses the use of a post-tax approach. **Therefore, Powerlink has (reluctantly) modelled its revenue requirement within this application using a post-tax nominal approach.**

4.3 The Cost of Equity Capital

Regulatory rate of return decisions in Australia to date have invariably employed the Capital Asset Pricing Model (CAPM) and the Weighted Average Cost of Capital (WACC) methodology for establishing returns for regulated businesses.

In the DRP, the ACCC has noted that in the absence of a more generally accepted approach, the ACCC will use the CAPM to estimate the benchmark return on equity.

The CAPM is the most widely accepted tool used to estimate the cost of equity capital. The CAPM is a linear equilibrium asset pricing model that expresses the cost of equity capital as a function of the opportunity cost of investing in the market, the market's own volatility and the systematic (undiversifiable) risk of holding equity in the particular company.

According to the CAPM the risks are classified into:

- Systematic Risk – the risk applicable to the market as a whole, such as level of economic activity, inflation, tax rises and interest rates; and
- Specific risk – the residual risk unique to an individual firm or a small group of companies that form a subset of the market.

The theory requires that specific risks that can be eliminated through diversification are not to be compensated.

The imputation adjusted cost of equity for Powerlink's transmission network business has been estimated using the following formula:

Imputation adjusted $K_e = [\{R_f + \beta_e{*}MRP\} + ARP]{*}\,(1\text{-}t) / \{1\text{-}t{*}(1\text{-}\gamma)\}$

Where:

R_f represents the rate of return on a risk free asset

β_e the equity beta, is a measure of the systematic or undiversifiable risk associated with the asset

MRP is the market risk premium

ARP is the asymmetric risk premium, which is discussed in section 4.3.3

t represents the corporate tax rate which has been assessed at 30%. This rate represents both the effective and the statutory corporate tax rate.

γ is a measure of the value of imputation credits.

Table 4.1 below summarises the parameters underlying the estimation of Powerlink's transmission network service business' after-tax cost of equity, K_e.

Table 4.1. Cost of equity estimate (as at 1 Feb 2001)

Parameter	Definition	Estimate Proposed
R_f	Nominal risk free rate	6%
MRP	Market risk premium	6%
β_a	(Base) asset beta	0.45
β_e	(Base) equity beta	1.12
β_d	Debt beta	0.00
γ	Value of imputation credits	0.45
K_e	CAPM cost of equity (adjusted for asymmetric risk)	13.97%
K_e * {1-t*(1-γ)}	Imputation adjusted cost of equity	11.7%

Each of these components is discussed below. It should be noted that these calculations are based on 1 February 2001 data.

4.3.1 Risk Free Rate

The risk free rate of return, in theory, represents the return on a zero-coupon asset of the same maturity as the relevant business. In practice, the yield to maturity on a long dated government bond has been used as a proxy for the risk free rate of return in the case of long term investments.

Given that the bulk of the underlying assets of electricity network businesses are long-lived and the allowable depreciation is based on extremely long asset lives, ideally the yield to maturity on a, say, 30 year Government bond would represent an appropriate proxy. In Australia, however, the longest dated bonds are typically ten year government bonds. Under such circumstances, the yield to maturity of the ten year bond rate is commonly adopted as the benchmark risk free rate.

The ACCC has expressed the view in its DRP, that the appropriate benchmark may be the five year government bond. We consider that these views are inappropriate for the following reasons:

- Standard finance practice in Australia is to measure the market risk premium relative to the ten year government bond and to quote historical estimates of the market risk premium on the same basis. The use of a five year government bond as a benchmark risk free rate, without any compensating adjustment, therefore distorts the term structure of the investment. Given the typically normal (upward sloping) yield curve, this practice will under-estimate the expected return on equity. Therefore, justifying its use on the basis that differences between short and long term rates are likely to be small may not be valid. In our view, depending upon the value of the regulatory asset base to which the return is applied, which in most cases, is substantial, even small changes in the rate of return can have a material impact on revenues.

- The view that regulated businesses will structure the maturities of their debt portfolios to match the length of the regulatory period is not realistic. A large number of submissions to the ACCC's consultations on its DRP noted that the regulator's assumption of regulated businesses re-weighting their debt portfolios every five years would in itself cause interest rate spikes in the debt markets. These spikes would coincide with each regulatory review, given their debt requirements relative to the size of the Australian debt market.

In the DRP, the ACCC has also indicated that it believes it is appropriate to adopt an average Government bond rate over a 40 day period. This approach exposes Powerlink to two major risks:

1. Interest rate risk, and

2. Refinancing risk

Using a 40 day moving average allows the potential for mismatch between the risk-free rate underpinning the WACC and the cost of debt. If the risk free rate is less than the corporation's cost of debt, profitability will be squeezed as the regulated business is unable to increase prices to cover the higher interest costs.

One risk minimisation strategy would be for the corporation to fully refinance its debt at the new determination date, locking in funds at the prevailing risk free rate for the regulatory period. This process, however, leads to potentially inefficient outcomes for regulated businesses and ultimately consumers. Having a large volume of debt maturing on and around the one date produces some practical capital market inefficiencies. By concentrating the maturity of intended debt near the end of the pending regulatory cycle, a regulated business will face a refinancing task that is likely to move the market and thus be completed over a range of market yields. Also, given the wide use of this approach for regulated entities in Australia, the timing of risk free rate determinations may lead to market spikes at and around reset dates (which financial market participants may seek to exploit and potentially influence). This will therefore become commercially sensitive information for the regulated organisations.

In addition, this strategy assumes all existing debt matures at the regulatory reset. In practice this is not the case, Powerlink has portions of its debt portfolio overlapping into the ACCC regulatory period which was drawn down at a higher cost of debt than the regulatory determination is likely to provide based on adopting the 40 day averaging approach.

Further consideration also needs to be given to borrowings required for capital expenditure during the course of the regulatory period. The organisation's financial position will come under pressure if the actual cost of debt achieved when drawing down new funds for capital expenditure is higher than the risk free rate underpinning the WACC assumption. This can to some extent be hedged by lengthening the maturity profile at the start of the new cycle, implying that the cost of debt on these new drawdowns has been locked in upfront. However, this presumes that the amount and timing of these new borrowings is certain. Whilst long-term capital works planning is undertaken, it can be difficult to specify the exact details of these requirements over such a horizon which is necessary to facilitate an effective hedge. This is particularly true in Queensland, where there is a high degree of uncertainty about the future generation pattern.

The range of the risk free rate in recent times (since May 1997) has fluctuated between 4.75% and 7.75%. The 40 day moving average risk free rate, based on the ten year government bond, is 5.48% to 31 January 2001. Sampling one short period before each five yearly reset date creates a risk that this may be a time when the market is stretched and not a true representation of the underlying fundamental circumstances.

A more sustainable approach to determining the risk free rate would be:

1. Lengthening the term of the moving average from forty days to twelve months – as at February 2001, this approach would give a risk free rate of 6.26%; or

2. Using an average of five 12 month moving averages for each year for the previous five years – as at February 2001, this would result in a risk free rate of 6.58%.

Based on the arguments presented above, we consider that the benchmark risk free rate should lie within the range of 5.48% to 6.58%. In order to attain a position that minimises the effect of the volatility associated with deep, liquid markets, Powerlink believes that the risk free rate should fall mid-range at 6%.

Should the ACCC adopt a benchmark risk free rate based on the 40 day moving average, we believe that the ACCC should add a premium to both the equity market risk premium and the cost of debt, in order to restore the internal consistency in the WACC calculation to address the risks considered above.

Powerlink proposes a nominal risk free rate of 6%

4.3.2 Market Risk Premium

The equity market risk premium represents the additional return over the risk free rate of return that an investor would require as compensation for the risks of investing in a diversified equity portfolio (e.g. the ASX All Ordinaries Index). It is essentially a measure of investors' appetite for risk. As such, one would expect short term measures of the market risk premium to vary considerably from one business cycle to the next, but stabilise when measured over longer time horizons spanning several business and market cycles. For this reason, a longer term measure of the market risk premium is generally preferred.

Empirical research by Professor Robert Officer suggested that it has been common practice in Australia to assume a market risk premium of between 6% and 8%. That research used data covering the one hundred year period from 1886 to 1987 and reported a 7.9% premium over the 10 year government bond. However, more recent empirical studies highlight that estimates of the market risk premia are highly sensitive to the measurement period chosen and the method of calculation.

The table below sets out the results of some of these more recent studies.

Table 4.2. Studies of market risk premiums

Source	Period	Risk premium (%)
AGSM:		
Arithmetic average, incl October 1987	1964-1995	6.2
Geometric average, incl October 1987	1965-1995	4.1
Arithmetic average, excl October 1987	1964-1995	8.1
Geometric average, excl October 1986	1964-1995	6.6
Arithmetic average	1974-1998	4.8
Geometric average	1974-1998	2.8
Officer:		
Arithmetic mean	1946-1991	6.0 to 6.5
Officer (1989) updated:		
Arithmetic mean	1900-1996	7.1
Geometric mean	1900-1996	5.4
Hathaway (1996)		
Arithmetic mean	1882-1991	7.7
Arithmetic mean	1947-1991	6.6

Based on the evidence presented above, Powerlink does not consider that sufficient evidence exists to warrant adopting market risk premia assumptions below the 6% to 8% range. Rather, our review indicates that recent (but not necessarily more relevant) studies provide evidence of low (e.g. 2.8%) as well as high (e.g. 7.7%) market risk premia, making the results inconclusive. The results support a range of interpretations. For example, one possible line of argument is that over longer measurement periods, the historic estimates would appear to support market risk premia as high as 7.7%. On this basis, it could be argued that the assumption of 6% that has been used in regulatory decisions to date, under-estimates the required rate of return.

In conclusion, we repeat our view that given the high degree of variation in results over differing measurement periods, we believe that it is difficult to definitively conclude that the market risk premium has permanently declined from the historical range of 6% to 8%. Any decision by the ACCC away from the range of premia used in previous regulatory determinations *must* be based on clear empirical evidence. We would therefore recommend that the 6% assumption be retained until further and more conclusive evidence becomes available and as this maintains consistency with the NSW and ACT Revenue Caps, SMHEA's determinations and the QCA's draft determination of the Queensland distribution corporations.

Powerlink recommends a market risk premium of 6%

4.3.3 Betas and Risk

Beta is a measure of an asset's risk relative to a market portfolio of assets such as the ASX All Ordinaries Index. It reflects the extent to which the returns on the asset co-vary with the returns on the market index, and hence, is a measure of the systematic or market risk of the asset. Under the CAPM, systematic risk is the only risk that is priced into asset returns since investors are deemed to hold diversified portfolios which result in the elimination of all unsystematic risk.

The standard approach to estimate the equity beta for unlisted businesses is to derive a proxy beta by "de-gearing" the observed equity beta of comparable listed companies. The resulting asset beta is then "re-geared" by the capital structure of the business to obtain a firm specific equity beta.

To date, rather than employing the technique described above, regulatory decisions in Australia have relied upon asset betas adopted in precedent regulatory decisions. Such decisions established an asset beta range of 0.40 to 0.45 for electricity network businesses and 0.45 to 0.50 for gas network businesses. These asset betas have then been re-geared by applying the "Monkhouse" formula shown below:

$$\beta_e = \beta_a + (\beta_a - \beta_d)*\{1 - [K_d/(1+K_d)]*(1-\gamma)*t_e\}*D/E\}$$

This approach for deriving equity betas has recently been criticised during the public consultation process for the ORG's determination on electricity distribution prices in Victoria, given that betas are not stationary over time, and hence, primacy should be given to observed empirical data. The ORG conceded the validity of this approach in its final decision. We consider that the ACCC should also adopt a similar approach.

Whilst strict adherence to finance theory implies that diversifiable risk is irrelevant in determining required rates of return, in practice, it is common to include a premium for diversifiable risk in estimating required returns. This practice reflects the view that diversifiable risks are not irrelevant to the value of an asset, since large, diversifiable risks, if unmanaged, can substantially reduce the value of an asset. This is clearly evident in terms of the discounted cash flow ("DCF") perpetuity model of the value of a firm, where diversifiable risks may not raise investors' required rates of return in the denominator of the model, but can significantly lower the level of a firm's expected cash flows in the numerator of the model.

We understand that in its TransGrid determination, the ACCC allowed for the following explicit risks:

- third party liability;
- the cost of self-insurance of assets;
- asset stranding; and
- "newness" of the regulatory regime.

These explicit risks, which have greater impact in the Queensland environment, are discussed in the table below.

Risk	Description
Third Party Liability	Risks associated with third party claims (which will be predominantly a result of network events) are considered greater in Queensland due to higher relative loading of the grid and lack of meshed network potentially exposing Powerlink to more claimable events. Even though Powerlink endeavours to insure against such events (the opex provision explicitly addresses the forward insurance projections), the non-insurable impacts of third party liability claims presents significant added investor risk.
The Cost of Self-Insurance of Assets	Insurance of transmission lines is very difficult to obtain and many TNSPs have been forced to self insure their lines. Risk of damage to lines is greater in Queensland due to the tropical/cyclonic environment. In the past, Powerlink has experienced several instances of major damage to the 275kV grid due to high winds costing many millions of dollars to repair. No allowance has been made in the forecast of operating costs for such contingent costs. In fact, the current regulatory arrangements do not allow for contingency funds to be carried forward to the next regulatory period within the opex allowance – it must therefore be included as an explicit risk margin.
Asset Stranding Risks	It has already been outlined in this section of the Application that transmission networks are subject to regulatory risks associated with asset optimisation, particularly as a result of asset stranding. In Queensland, risks of stranding will significantly increase due to the impacts of excessive generation capacity and introduction of a new gas transmission network. While the ACCC's regulatory principles seek to address this issue through its accelerated depreciation principles, such principles will only capture the effects of a portion of the stranding impacts envisaged in Queensland. These market risks could either be ameliorated either by allowing for an explicit additional depreciation allowance at each regulatory reset or by allowing an additional explicit equity risk premium.
"Newness" of the regulatory regime	The Statement of Regulatory Principles has not been progressed since the TransGrid decision. In fact, a range of NEC changes have emerged over that period which signal a greater emphasis on asymmetrical risk being assigned to the TNSPs, eg. the REIMNS review, the Transmission and Distribution Pricing review, and pressures from participants to pursue property right and firm access proposals.

We concur with the ACCC's treatment of the above risks. However, we note that the risks associated with the possible asymmetric adjustments made under the regulatory regime was not adequately allowed for by the ACCC. The subject of asymmetric risk is discussed quite clearly in a paper by OXERA[2], which formed part of a submission by the Australian Pipeline Industry Association ("APIA") in

[2] Oxford Economic Research Associates Ltd, Regulatory Risk, APIA submission, June 17th 1998.

relation to the Victorian gas access arrangements. The following quote has been extracted from the paper:

> *"The premium [for asymmetric risk] provides a measure of the risk associated with the asymmetric nature of regulation. While it is unrelated to the non-diversifiable risks which are reflected in a company's beta value, it nevertheless represents a risk to which investors attach a cost and for which they expect to be adequately compensated."*

In addition, OXERA also noted a study by Conine and Tamarkin (1985)[3] that estimated a *premium of 1.3% to the cost of equity to account for asymmetric risk:*

> *"This model proposes a second risk parameter, γ, is added to the conventional CAPM measure of non-diversifiable risk beta to take account of the risks an investor faces from the skewness of returns, as illustrated below.*
>
> $$E\,(r_e) = r_f + \beta\,(E(r_m) - r_f) + \gamma\beta$$
>
> *…*
>
> *Studying 60 utilities in the USA over a period of five years, Conine and Tamarkin (1985) calculated the expected return on the basis of standard CAPM and the three-moment model incorporating the γ factor. While the former implied a cost of equity in the region of 15.81%, the latter suggested 17.16%, implying an increase of 1.3% in the cost of equity. These findings suggest that the impact of asymmetric returns could be particularly significant."*

Powerlink considers that asymmetric risk is a legitimate risk for which some compensation should be allowed in estimating an appropriate regulatory rate of return, in addition to the other risks compensated through the formal CAPM. The study referred to above demonstrates that its impact is potentially material. In our view, the most workable method of incorporating these risks is to allow for an explicit premium in the cost of equity. We consider that a premium of around 1.3% represents a reasonable adjustment given the significant risk of asset re-optimisation that faces Powerlink. This risk is due to the uncertain nature of new generation projects, possibility of embedded generation and changing fuel market dynamics in Queensland, including the likely development of a major gas pipeline parallel to, and in direct competition with, the transmission grid.

[3] Connine, T. and Tamarkin, M. (1985), Implications of Skewness in Returns for Utilities' Cost of Equity Capital, Financial Management (referred to in the paper by OXERA).

A working paper entitled "Estimation of Additional Asset Risks Associated With New Queensland Gas Transmission Projects" (Attachment 1) quantifies the level of risk associated with such optimisation. This paper demonstrates that a 1.3% equity risk premium, based on the asymmetric risks attributable to regulatory optimisation, associated with new gas transmission alone, is conservative. When considered in conjunction with other regulatory risk drivers associated with Queensland's transmission environment, as outlined in this Chapter, the 1.3% risk premium must represent the lower end of the acceptable range.

Table 4.3 below sets out information on the observed equity betas of selected utilities listed internationally. Given that equity betas are affected by financial risk, we have also "ungeared" the equity betas to derive the equivalent asset beta.

Table 4.3. Equity betas of selected comparable companies

	Country	Equity beta β_e	Asset beta β_a
UK comparable companies			
Hyder PLC	UK	0.38	0.10
Scottish Power PLC	UK	0.41	0.28
Scottish & Southern Energy	UK	0.32	0.26
United Utilities PLC	UK	0.57	0.33
Viridian Group PLC	UK	0.24	0.18
Simple average UK		**0.38**	**0.23**
USA comparable companies			
AGL Resources	USA	0.46	0.29
Nicor Inc	USA	0.47	0.33
Duke Energy Inc	USA	0.32	0.23
Energen Corp	USA	0.75	0.48
Utilicorp United Inc	USA	0.45	0.24
Cinergy Corp	USA	0.43	0.25
RGS Energy Group Inc	USA	0.45	0.25
GPU Inc	USA	0.45	0.18
American Electric Power	USA	0.43	0.21
Simple average USA		**0.47**	**0.27**
United Energy ltd	AUS	0.74	0.47
Australian Gas Light	AUS	0.48	0.32
Envestra Limited	AUS	0.33	0.06
TrustPower Limited	NZ	0.60	0.45
Simple Average Aust / NZ		**0.54**	**0.33**

	Country	Equity beta β_e	Asset beta β_a
Simple average – All		**0.46**	**0.27**

Note:

1. *Market capitalisation is based on share price on 30 November 2000*
2. *Equity betas represent Bloomberg adjusted betas;*
3. *Asset betas derived using the formula $\beta a = \beta e * E/V$ (assumes $\beta d = 0$)*
4. *All data sourced from Bloomberg.*

The impact of the type of regulatory regime on beta risk should not be underestimated. Empirical research undertaken by the World Bank suggests that regulated businesses that are subject to incentive regulation typically exhibit higher betas than their counterparts who are subject to rate of return regulation. Intuitively, this result is not surprising given that incentive regulation is relatively less intrusive and allows actual returns to vary from benchmark regulated returns.

The average asset betas set out above range from 0.23 to 0.33. As noted above, the asset betas were derived assuming that the debt beta was zero. This assumption was adopted to simplify the derivation of the asset beta estimate, however, we note that to the extent that debt betas are positive, it has the effect of producing asset beta estimates that are biased downwards. We therefore expect that an appropriate asset beta for a transmission network service business such as Powerlink would lie in the range 0.40 to 0.50. Given the newness of the regulatory regime in Australia compared with those in the USA and UK, which are reflected in the above comparators, we consider that an asset beta mid-range (i.e. 0.45) would be appropriate[4].

Applying the “Monkhouse” formula (and using the assumptions on the debt beta, effective tax rate, value of imputation credits and debt margin as discussed in this report), we estimate a base equity beta in the range of 0.77 to 1.12 based on this assumption. Due to the risk that Powerlink is exposed to as a result of unforeseen market outcomes we propose the base equity beta be valued at 1.12.

[4] We note the Commission, in the TransGrid decision, allowed for the risks associated with the newness of the regulatory regime by selecting a return on equity of 13.85%, which was towards the high end of the assessed feasible range of 11.5% to 14.25%. This result implies a premium of 97.5 basis points above the midpoint of the feasible range.

The CAPM cost of equity estimate that results from applying a risk free rate of 6%, a market risk premium of 6%, and a base equity premium in the range of 0.77 to 1.12, falls into the range of 10.61% to 12.67%. Factoring in the proposed 1.3% premium for asymmetric risk yields a CAPM cost of equity (adjusted for asymmetric risk) in the range of 11.91% to 13.97%.

The proposed value for equity beta is 1.12 and the corresponding cost of equity is 13.97%

4.3.4 Imputation Credits

Under Australia's dividend imputation system, domestic equity investors receive a taxation credit (i.e. a franking credit) which is attached to any dividends paid out of after-tax company returns. This franking credit, which reflects the amount of tax that has been paid by the company on each dollar of dividend, may be used to offset the personal tax of the investor, and hence, represents additional cash flow to the investor after-company and personal tax. Without the franking rebate, shareholders would, in effect be paying personal tax on profits that had already been subject to company tax. In a sense, therefore, franking credits effectively represent personal tax collected or withheld at the company level.

In recent years, there has been an emerging consensus that dividend imputation represents additional value which accrues to equity investors. As such, there is general acknowledgment that the value of imputation should be recognised. However, the appropriate value to attribute to imputation credits remains a highly controversial issue.

In principle, both finance academics and practitioners agree that the value attributed to imputation tax credits should take into account the following factors:

- the rate at which the "average" company distributes imputation credits. This is indicated by the imputation credit payout ratio; and

- the proportion of distributed imputation credits redeemed or utilised by the "average" investor. The ability of an investor to utilise imputation credits clearly depends upon his/her tax status.

To the extent that the average company distributes *all* of its imputation credits and the average investor can utilise *all* of these franking credits to offset his/her personal taxes, to that investor, the corporate tax paid by the company can effectively be regarded as a withholding of personal taxes. Under such circumstances, the investor is likely to value the imputation credits at 100% of face value. In reality, however, companies rarely distribute all of their franking credits and not all investors are able to utilise their franking credits entitlements. Consequently, any value that is attributed to imputation credits is likely to be less than 100% of its face value.

Empirical research that has been undertaken on the value of imputation credits have largely employed a methodology known as “dividend drop off” analysis. This methodology examines the fall in the share price of a company on the date a franked dividend is paid. To the extent that the drop in the share price exceeds the cash value of the dividend, the additional drop-off is attributed to the value of the franking credits attached.

Powerlink’s financial advisor, KPMG, has consistently maintained that the value of 50% for γ may overstate the value of imputation tax credits. Given the lack of definitive empirical evidence in this area, their view has been based upon the logic that dividend drop-off rates do not take into account the value of imputation tax credits that are not immediately distributed by the company. Undistributed franking credits are likely to have some value, however, this value would depend upon the timing of their distribution. The longer they are retained by the company, the lesser will be their present value to shareholders. Since the adjustment for γ implicitly assumes a 100% imputation credit payout ratio, the appropriate value of γ should take into account the value of both distributed and retained credits. It is on this basis, that KPMG has formed a view that the value of γ is likely to be less than 50%.

The ORG, in its recent price decision for the Victorian electricity distributors, supported its choice of a value of gamma of 50%, by reference to research undertaken by Professors Neville Hathaway and Robert Officer[5] (using national tax statistics) which indicated the following:

- on average, 80% of company tax payments are distributed as imputation credits; and

[5] Hathaway, N and R. R. Officer, The Value of Imputation Credits, 1999 Cost of Capital Conference Paper, Melbourne Business School (the paper was first presented at a Pacific Basin Finance Conference in New York in December 1991. Further presentations have been made at seminars in Sydney, Brisbane and Melbourne during 1992, 1993 and 1995).

- on average, 60% of the distributed credits are redeemed by taxable investors. This "redemption value" is consistent with the results of Hathaway and Officer's dividend drop off analysis, which found an average drop-off "market value" of credits between 50% -60% of their face value.

These two results, when compounded, indicate that approximately 48% of company taxes paid represents, in effect, personal taxes withheld at the company level (i.e. "gamma").

However, in interpreting the results of Hathaway and Officer's study, it should be noted that the results represent what the authors refer to as the "conditional value" of franking credits. That is, because the measures of credit value (i.e. national tax statistics and dividend drop-off analysis) are taken *after* the company has announced the payment of the dividends and credit, there is no uncertainty about the timing and the amount of the credit embodied within these measures. In reality, investors face uncertainty about how much credits a company will distribute, and the timing of the distribution, in forming their views on expected returns. Accordingly, one would expect to apply a discount rate to allow for this uncertainty. However, as Hathaway and Officer point out, the exact discount rate remains obscure.

We expect that a more conclusive view on the value of gamma will only be formed over time, as more research is undertaken in this area. However, our review of Hathaway and Officer's study indicates some support for the view that a value of 50% for gamma is unlikely to be conservative - rather, it is likely to represent the upper end of a feasible range. On this basis, and in the absence of further reliable evidence, we recommend that the value of gamma should not be increased above 50%. We consider a feasible value for gamma is in the range of 0.40 to 0.50.

Powerlink proposes a value of gamma to fall mid-range at 45%

4.4 Cost of Debt

In practice, the debt risk premium on debt is typically estimated from observed yields to maturity (R_d) on debt securities of comparable risk and maturity.

In establishing the cost of debt ranges regulators have, in the past, adopted the view that:

- the cost of debt should abstract from reference to the specific entity's cost of debt, as the company-specific cost of debt may not reflect efficient finance sourcing; and

- the cost of debt should reflect the prevailing cost of accessing fixed rate debt in the indexed bond market.

However the most recent determination by the QCA, in relation to the Queensland distribution corporations, indicates that the application of these principles may have under-stated debt margins in previous decisions. This is due to the small size of the Australian market for fixed rate debt relative to the funding requirements of the industry.

The draft decision of the QCA adopted a debt margin of 160 basis points based on the margin attracted by BBB rated debt. The QCA stated that :

> *"BBB rated debt currently attracts yields up to 200 basis points above the redemption yield on 10 year Commonwealth Government Bonds…….. The Authority's own analysis suggests that, if the prescribed distribution activities were considered in isolation from the DNSPs' total business activities, and if the gearing levels used were those associated with the proposed industry average debt to total capital ratio of 60 percent (as discussed below), then the effective credit rating would be in the range of A- to BBB. Under current capital market conditions, debt rated in this range typically display margins in the range of 120 to 190 basis points. Debt rated at BBB+ attracts a margin of approximately 160 basis points." (QCA Regulation of Electricity Distribution Draft Determination, page 75)*

In a recent regulatory decision by the ORG in relation to the Victorian electricity distribution businesses, a debt margin of 150 basis points was set by giving consideration to the following:

"Westpac agreed that a long-term fixed rate financing benchmark is not an efficient benchmark. However, it argued that "the current capacity within the index-linked market is well short of meeting the funding requirements of the entire Victorian distribution businesses". It estimated current capacity at $600 million, plus a further $1 billion through the CPI swap market. It also argued that it would be unreasonable to assume that this capacity could be filled in a short time, without an adverse impact on credit spreads of the underlying real risk-free rate. It estimated these incremental costs to be in

the order of 25 – 35 basis points;" (ORG Electricity Distribution Price Determination 2001-2005, Vol 1, page 287)

The ORG also noted further evidence from a submission by United Energy on this issue:

"In a later submission, United presented further views (based upon advice from Westpac) about the cost of funding in index-linked terms. It stated that, if it wanted to finance in index-linked terms, and was the first to issue, it would cost it between 145 basis points or 170 basis points for 10 or 15 year terms (based on its current A- credit rating). However, if it was not the first to issue, the cost would be 175 basis points or 210 basis points for 10 or 15 year terms. In any case, United Energy could only access about $100 -$150 million of this source of funds. For the remainder, it would need to issue physical bonds and use CPI swaps. It estimated this cost to be 185 basis points or 230 basis points for 10 or 15 year terms. United Energy concluded that a debt margin of 200 basis points is warranted." (ORG Electricity Distribution Price Determination 2001-2005, Vol 1, page 288)

We consider that the evidence presented by Westpac referred to in the ORG's decision should be taken into account in setting the appropriate debt margin for Powerlink. The ORG's decision to apply a debt margin of 150 basis points and the recent QCA determination to adopt a debt margin of 160 basis points represents precedents that should be noted by the ACCC in its determination for Powerlink.

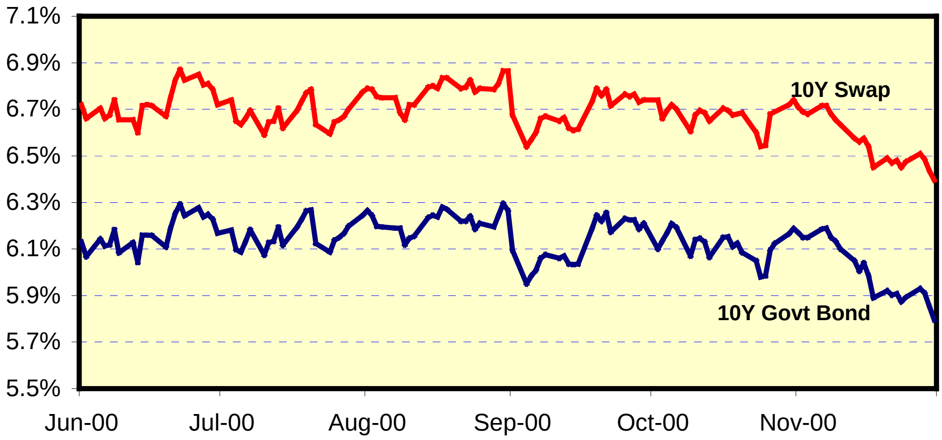
The required margin for Powerlink's transmission network business should take into account:

- the likely credit rating of the regulated entity given the level of gearing assumed (i.e. 50% to 60%). In practice, it is assumed that the gearing level is consistent with the business being awarded an investment grade credit rating (i.e. BBB+ to A-) as this is the level the business would seek to achieve to optimise its capital raising opportunities and costs.;
- the annualised cost of upfront fees payable to raise debt finance; and
- the cost of hedging a floating interest rate exposure, which is indicated by the spread between the long term bond rate and the swap rate of equivalent duration (the "bond-swap" spread).

The 10 year bond-swap spread which has ranged from 50 bp to 64 bp over the six months ended 30 November 2000, and averaged around 55 bp, is currently around 60 bp. As indicated by the chart below, the spread has *widened* marginally in recent months. It should also be noted that the size of the spread can vary with changes in supply and demand for hedging. In the submissions to the regulators during the Victorian Gas Access Arrangements public consultation process, it was noted that in previous privatisations, the bond-swap spread has increased by as much as 20 bp in anticipation of the winning bidder being required to hedge their floating interest rate exposure.

In addition, as discussed above, the ORG in its recent decision on the Victorian electricity distributors, allowed a premium in the debt margin to reflect supply constraints in the market for indexed bonds. According to submissions to the ORG, such constraints could result in credit spreads widening by as much as 25 to 35 basis points.

Australian Dollar 10Y Bond v. 10Y Swap Rate



Based on the above, we consider that the approximate all-in debt margin for Powerlink's transmission business, taking into account the impact of potential supply constraints in the market for indexed bonds, would be in the range of 145 bp to 189 bp given a gearing level of 60%. Assuming a risk free rate of 6%, this translates to a pre-tax cost of debt ranging from 7.5% to 7.9%.

Powerlink proposes a mid-range debt margin of 167 bp and a resulting pre-tax cost of debt of 7.7%

4.5 Capital Structure

In deriving the return on equity and cost of debt it is necessary to determine an appropriate capital structure of the transmission network.

Schedule 6.1 (5.1) of the NEC states that:

> *"Gearing should not affect a government trading enterprise's target rate of return…. For practical ranges of capital structure (say less than 80 per cent debt), the required rate of return on total assets for a government trading enterprise should not be affected by changing debt to equity ratios"*

The ACCC adopted a gearing ratio of 60 per cent in both the SMHEA and the NSW and ACT Revenue determinations based on industry wide benchmarking, as did the QCA in relation to the Queensland distribution companies.

Therefore, consistent with recent regulatory decisions Powerlink proposes gearing of 60%.

Powerlink proposes a gearing level of 60%

4.6 Inflation Rate

The expected inflation rate is an inherent aspect of the risk free rate and cost of debt parameters, even though it is not an explicit parameter in the WACC calculation. Inflationary expectations are determined through financial markets and government estimates. An indication of inflation from financial markets is provided by the difference in nominal and indexed bonds over a corresponding period. The Commonwealth Treasury also releases inflationary predictions based on internal modelling.

Powerlink believes that it is more appropriate to derive the expected inflation rate from the combination of the Commonwealth and indexed bond rates. This is consistent with the approach used in the NSW and ACT Revenue Cap and also SMHEA's determination, and QCA's draft determination in relation to the Queensland distribution corporations. Powerlink considers that an appropriate inflation rate is 2.5% for the period 2002 to 2007.

The above inflation projections exclude any short term impacts of GST and are considered representative of the long term underlying inflation rate. Powerlink reserves the right to make a submission in respect of the medium term GST impact when more detailed information becomes available at the end of the 2000/01 financial year.

Powerlink proposes an inflation rate of 2.5%

4.7 Summary

We have estimated a feasible regulatory rate of return for Powerlink's transmission network business in the range of 7.05% to 8.08%. This result, which is expressed in *post-tax nominal terms*, is based on the WACC approach and application of the Capital Asset Pricing Model ("CAPM"). Adjustments have been made within the CAPM to accommodate the impact of dividend imputation on the cost of equity. The equivalent results expressed in pre-tax real terms is a range of 7.39% to 8.82%.

Powerlink proposes a post-tax nominal WACC of 7.91% and a post-tax return on equity of 13.97%

The key input parameters underlying our calculations are summarised in the table below.

Table 4.4. Summary of results

Definition / Parameter	Feasible range	Powerlink Proposal
Post-tax nominal WACC after allowing for imputation	7.05% - 8.08%	7.91%
Pre-tax real WACC after allowing for imputation	7.39% - 8.82%	8.58%
Pure "vanilla" WACC	9.23% - 10.32%	10.19%
Post-tax return on equity (CAPM)	11.91% - 13.96%	13.97%
Pre-tax cost of debt	7.5% - 7.9%	7.7%
Statutory corporate tax rate (applied to taxable income)	30.0%	30.0%
Effective corporate tax rate (based on cash flow modelling)	30.0%	30.0%
Value of imputation credits	0.40 – 0.50	0.45
Long term proportion of debt funding	60%	60%
Long equity proportion of equity funding	40%	40%
Inflation	2% - 3%	2.5%

5 Cost Allocation Principles

5.1 Introduction

Powerlink Queensland is a government owned corporation which operates and maintains Queensland's high voltage electricity transmission network. Powerlink is a stand-alone transmission entity, and does not engage in the generation, trading or retailing of electricity.

The majority (94%) of Powerlink's revenues come from operating the shared transmission network in Queensland, and are therefore regulated. However, Powerlink earns some revenues from non-regulated activities:

1. contestable network activities (2%) – eg. the provision and operation of network assets between a new power station or new load and the shared grid;

2. non-network activities (4%) – eg. technical consulting services such as oil analysis, and engineering consulting.

In relation to category 2 above, Powerlink's financial systems have for many years enabled separate recording and reporting of revenues and costs for these non-regulated non-network activities, and the recently implemented SAP R/3 systems continue to provide this capability.

However, in relation to category 1 above, the contestable network assets, Powerlink's legacy systems did not provide such a separation for the costs. The new SAP system has this capability, and will continue to provide that separation of costs into the future, but there is no history.

The information in this Chapter 5 was provided to the ACCC in late 2000 in advance of this submission.

5.2 Purchaser / Provider Model

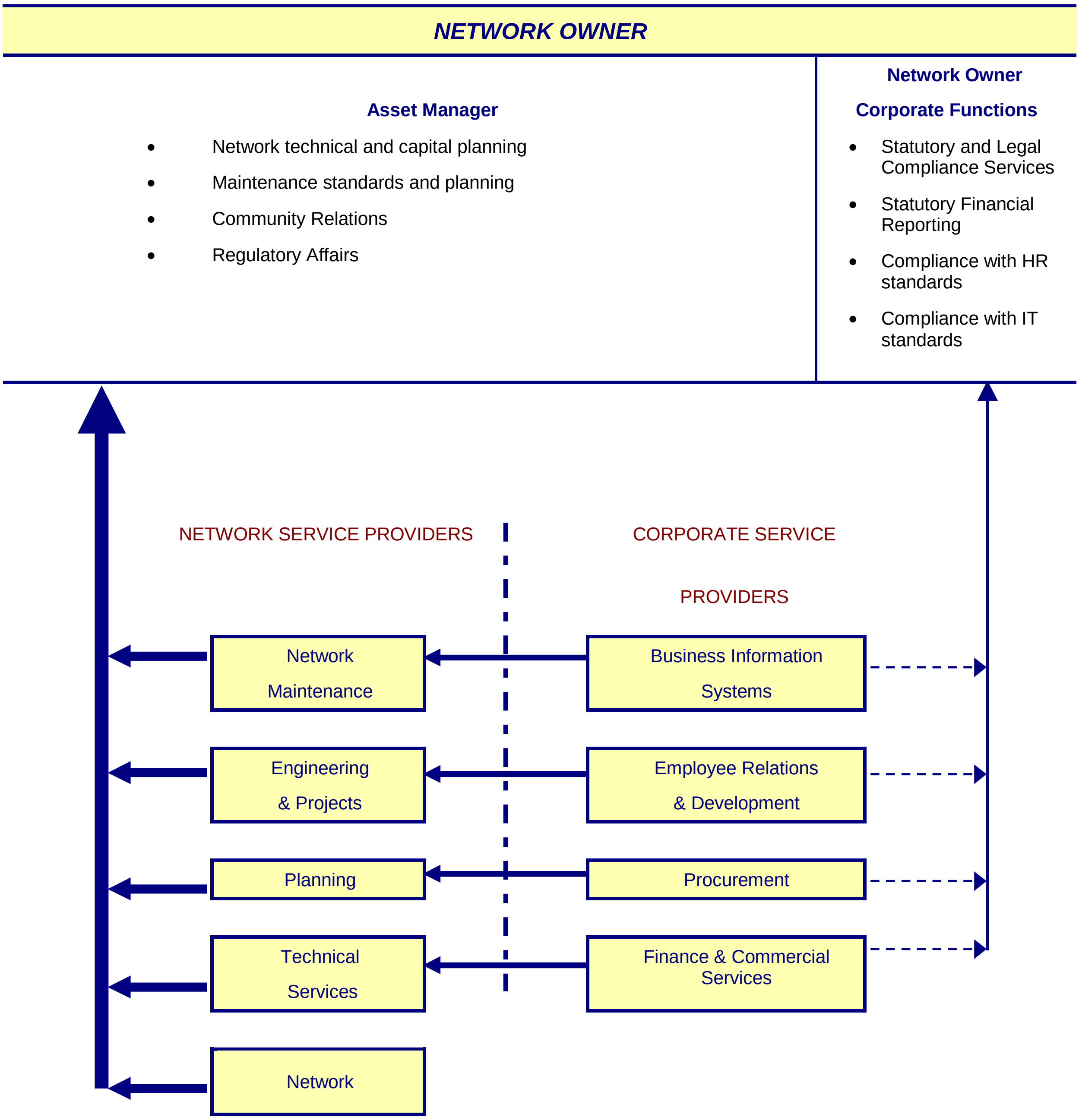
Powerlink operates an Asset Manager / Service Provider Model to provide the basic structure by which the corporation manages the transmission assets and activities. The Asset Manager / Service Provider model segregates the "purchasers" of goods and services from the "providers" of those services (both internal or external).

In this model, the "Network Owner" is that part of Powerlink that exists to fulfil the functions assigned under the Electricity Act as a "Transmission Entity", and other related legislation such as the GOC Act, Corporations Law, Income Tax Act, etc. The Network Owner makes decisions on policies recommended by the Asset Manager. The Asset Manager then implements approved polices and the service providers take action in accordance with these policies.

The Network Owner incorporates the functions of:

- Asset Manager;
- Corporate Service Provider functions necessary to support the corporate responsibilities of Powerlink; and
- Corporate Governance Arrangements

Services are provided to the Network Owner and other service providers. These relationships are represented diagrammatically below:



The Purchaser – Provider model therefore provides the underlying philosophical rationale for costing within Powerlink.

5.3 Supporting Systems

As mentioned above, Powerlink has recently implemented the SAP computer software, which provides a fully integrated system for tracking costs (and activities) *from their original source* to their ultimate allocation, regardless of whether these costs are incurred within or external to Powerlink. The original source might be labour timesheets, purchase orders, inventory requisitions, invoices etc. SAP enables this basic costing data to be entered once only at its source, and then allocated to the correct project, job, cost centre etc.

Within SAP system:

A. each capital project is separately identified, and is broken down into a hierarchy of sub-projects, and sub-sub-projects etc. to enable costs to be firstly estimated then actual costs to be collected for each package of work done. At the lowest project level, these costs can be identified as regulated or non-regulated in nature, enabling non-regulated capital activities to be separated AT SOURCE from regulated activities;

B. each job or activity (e.g. a maintenance job on Powerlink assets, or a job for an external customer) is separately identified by a Work Order. This allows non-regulated activities (e.g. oil testing for an external customer) to be separated AT SOURCE from regulated activities (e.g. maintenance on a regulated circuit breaker) . Because costs (labour, materials, services etc) can be charged to an individual Work Order, then costs of non-regulated activities are automatically segregated at source;

C. each maintenance asset is separately identified (regulated or non-regulated) and the costs of the above-mentioned Work Orders are assigned – at the creation of the Work Order – to an asset or a group of assets. Thus, work on non-regulated assets is also separated AT SOURCE from work on regulated assets, and the aggregation of costs follows automatically;

D. each financial asset is separately identified (regulated or non-regulated) and the depreciation expense of each asset separately identified AT SOURCE as regulated or non-regulated.

In short, the SAP system totally supports the separation of the DIRECT costs for regulated activities from the direct costs for non-regulated activities AT SOURCE.

Of course, indirect/overhead costs still require an allocation mechanism, and this is discussed in Section 5.6.

Powerlink's previous systems partly supported feature B above but not features A, C or D – thus there is a history of separation of costs for non-regulated activities which are "non-network " services (eg. oil testing, consulting) but no history for the non-regulated network activities.

In providing data to the Queensland Interim Regulator (ERU) for its most recent determination, Powerlink used an "averaging" approach – that is, it attributed the same operating and maintenance costs (as a % of asset value) to its non-regulated assets as it experienced on its regulated assets.

We believe that this approach is more likely to OVERSTATE the real costs of operating and maintaining the non-regulated assets as:

1. those assets have a much lower age profile and newer technology, and thus should have lower maintenance costs in the short term; and

2. those assets are typically closer to maintenance depots, and thus should have lower maintenance costs.

As mentioned, the recently implemented SAP system enables Powerlink to separately capture the actual costs of operating and maintaining those non-regulated assets.

At the 1 July 1999 valuation, the non-regulated assets were only about 1.5% of the total assets.

5.4 Charging Models

The Asset Manager / Service Provider Model adopted by Powerlink identifies the possible charging methodologies for customers as follows:

- ❖ **Cost Centre** Do not charge, but only collect costs
- ❖ **Revenue Centre** Charge at full cost with the objective of cost recovery

- **Profit Centre** Charge at a commercial rate with the objective of achieving a budgeted profit or loss
- **Investment Centre** Charge at a commercial rate with the objective of achieving a commercial rate of return

Powerlink's policy is that in all cases, **external** customers for NON-REGULATED services are charged at commercial rates, e.g. for engineering consulting work, the chargeout rate for an engineer is based on the ACEA rate for that individual's qualifications and experience.

As a consequence, non-regulated non-network services are provided with the objective of making a profit, and can be regarded as "Profit Centres". The historical data shows that these services have been, and continue to be profitable, with the profit levels reflecting those of our competitors for those services. No competitor has ever made a claim of sub-commercial pricing of such services against Powerlink.

Non-regulated NETWORK provision is treated as an "Investment Centre" – Powerlink is required to make an investment in these assets, and to take on various risks as part of the negotiation process to win this contestable business. Powerlink therefore prices these services with the objective of earning a commercial rate of return on its investment, commensurate with the risks. Any additional costs associated with these risks are allocated to the appropriate non-regulated investment centre.

Australian Accounting Standards do not allow for the recognition and reporting of internal profits within an entity. Profits can only be recognised when goods and services are sold to another legal entity. Consequently, the "Investment Centre" and "Profit Centre" models are NOT appropriate for the provision of Internal Services, e.g. services from an Internal Service provider to the Asset Manager, or from a Corporate Services provider to an Internal Network Service provider.

For the provision of internal services, Powerlink has chosen the "Revenue Centre" model.

This model ensures a consistency of approach between services provided internally (full cost recovery including overheads) and services provided externally (full cost recovery including overheads plus a profit margin). It imposes a discipline of commercial costing and pricing for services.

5.5 Labour costing

Powerlink adopts a “standard costing” approach for internal labour charges. Standard Labour Rates are determined for each “pool” of employees, based on wage/salary level groupings.

The standard labour rate incorporates: -

- Basic Labour Cost (wages /salary); *plus*
- Labour Oncosts (e.g. workers compensation, payroll tax); *plus*
- A share of the supervisory and administration costs for that employee’s team

Advantages of the standard costing approach include:

- estimation of labour costs for budgeting or for quoting work is much simpler;
- any employee in a given “pool” costs the same;
- the full labour costs per hour for employees are highly visible and easily comparable to market rates (where relevant).

The employment and award related costs which comprise the Labour oncost component include Annual Leave, Sick Leave, Statutory Holidays, Long Service Leave, Payroll tax, Superannuation, Workers’ Compensation Insurance.

The timesheet information for each employee entered into the SAP system includes not only the hours worked (to feed payroll calculations) but the *dissection* of hours worked on each work order, project, cost centre etc. The SAP system applies the standard labour costing rate to these booked hours and automatically posts the labour costs to the appropriate job, project or cost centre.

5.6 Corporate Overheads and Non-Regulated business

The methodologies outlined above result in most costs being charged DIRECTLY via timesheets, invoices, etc to the appropriate cost centres, projects, work orders etc. As mentioned previously assets, projects and work orders are separated at creation between regulated and non-regulated business, thus making separation of costs (and revenue) between regulated business and non-regulated business an automated process.

The only remaining costs are corporate overheads e.g. Board costs, financial and statutory compliance costs, etc. Given that almost all of Powerlink's revenues are regulated (in 99/00 over 94% of total revenue), an "Avoidability Cost" methodology is applied to corporate overhead costs to determine the amount of each item of corporate overhead to be applied to non-regulated activities.

The objective of the "Avoidability Cost" methodology is to identify the corporate overhead costs of operating the regulated business. This methodology identifies which costs would be avoided if non-regulated activities did not exist. Those costs that cannot be avoided are attributed to the Network Owner as regulated costs.

The "Avoidability Cost" methodology provides a more accurate allocation of costs rather than arbitrarily allocating costs by merely averaging them on some artificial basis e.g. budgeted costs, or number of personnel. Instead, the "Avoidability Cost" methodology uses the cost drivers as the basis of allocation to the Network Owner or internal service providers.

For some major lines of non-regulated activity, the outcomes of the "Avoidability" methodology can be checked by using a "Commercial Cost comparability" methodology.

This methodology involves establishing the "best practice" total operating costs for a (private sector) business entity that provides the same services as the particular non-regulated business line within Powerlink, (for example, oil testing). Such comparisons support the use of the "Avoidability Cost" methodology.

5.7 Summary

- Regulated revenues account for almost all (94%) of Powerlink's total revenues. This proportion is not envisaged to change during the upcoming regulatory period.

- Non-regulated network revenue accounts for about 2% of Powerlink's total revenues. In the absence of specific historical data, operating and maintenance costs have been assigned to these non-regulated assets on a pro-rata basis vis a vis the regulated assets. This tends to overstate the costs of the providing these non-regulated services.

- Non-regulated technical and consulting services (non-network) account for about 4% of Powerlink's total revenues. The revenues and costs for these services have historically been separated, using sound and proven methodologies.

- Powerlink's Asset Manager/Service Provider business model is a "Purchaser/Provider" model which enables clear identification of all internally and externally provided services and which clearly separates the direct costs of services from the costs of corporate overheads.

- Powerlink's new SAP computer systems enable the separation of regulated assets and regulated activities from non-regulated assets and non-regulated activities AT SOURCE, and thus provide for separate recording and reporting.

- Powerlink applies one of a number of charging methodologies (Investment Centre, Profit Centre, Revenue Centre, Cost Centre) to reflect the nature of each activity. Non-regulated services are provided on a fully commercial basis.

- The labour costing methodology and the "at source" time recording capabilities of SAP ensure appropriate allocation of full labour costs between regulated and non-regulated activities.

- Corporate overheads are allocated to service providers using an "Avoidability Cost" methodology, and comparisons have been done using a "Commercial Cost" comparability model to validate the level of overhead resulting from the allocation methodology.

- Corporate overhead costs allocated to service providers are then incorporated into standard labour rates that are charged via timesheet to regulated and non-regulated activities.

Powerlink Queensland believes that the comprehensive methodologies adopted throughout the organisation are appropriate given the small size and labour-intensive nature of the non-regulated services. The Operating and Maintenance Expenditure, Capex, Powerlink's asset base and depreciation have all been separated into regulated and non-regulated in accordance with the above principles.

6 Opening Asset Base

6.1 Introduction

The first regulatory period for which the ACCC will set Powerlink's regulated revenue commences on 1 January 2002, which is midway through Powerlink's financial year. To avoid the unnecessary expense of auditing Powerlink's accounts in January 2002, it is proposed that the accrual building block methodology for revenue determination is based on a whole year approach. The opening asset value for the purposes of this revenue decision will be at 1 July 2001. This opening value (at 1 July 2001) has been derived from:

- An independent valuation undertaken by the jurisdictional regulator as at 1 July 1999;
- Adjustments which Powerlink believes need to be made to that valuation;
- The roll-forward of that valuation to 1 July 2000, based on capex, depreciation and revaluation (which were audited as part of Powerlink's 1999/2000 financial reports);
- A roll-forward to 1 July 2001 based on <u>projected</u> capex, depreciation and revaluation.

6.2 Overview of Valuation Process

Figure 6.1 shows a diagrammatic overview of the asset valuation processes as set out in the NEC. This process is discussed below.

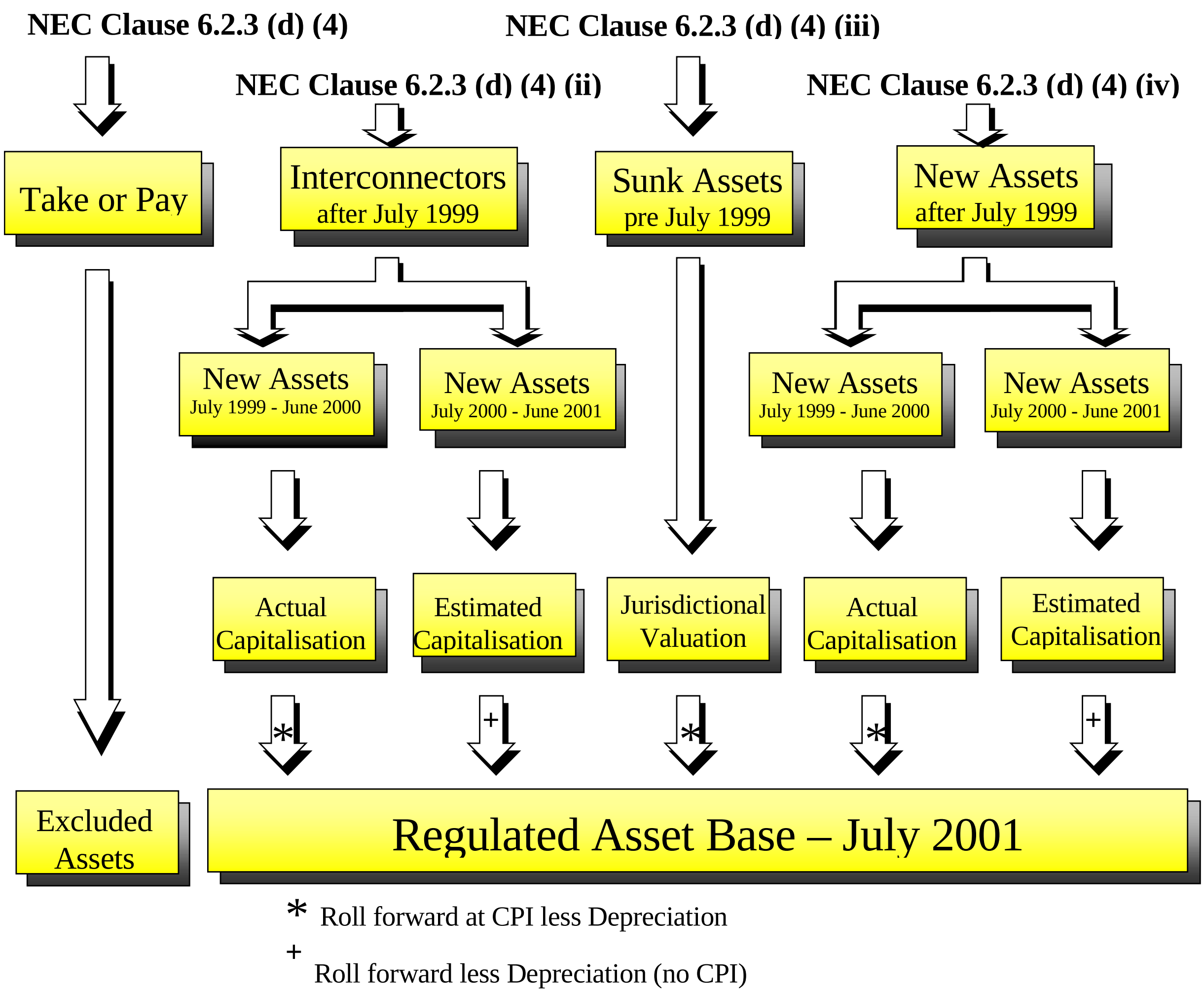


Figure 6.1. Asset Valuation Process Overview

6.2.1 Asset Categories

Clause 6.2.3 (d) (4) of the NEC defines four categories of assets in relation to valuation, viz:-

- Assets created under a take or pay contract - NEC Clause 6.2.3 (d) (4) (i);
- Assets created under network augmentation under NEC Clause 5.6.5 - NEC Clause 6.2.3 (d) (4) (ii);
- Assets known as “sunk assets” - NEC Clause 6.2.3 (d) (4) (iii);
- Assets known as “new assets” - NEC Clause 6.2.3 (d) (4) (iv).

Take or Pay Assets

Assets which fall into the take or pay category include those which were provided under contracts which receive payments that are financed from regulated revenue. While Powerlink does have assets supported by non-regulated take or pay arrangements, it does not currently have regulated “take or pay” assets.

Clause 5.6.5 (Interconnector) Assets

Assets which fall into this class (“Interconnector assets”) include inter-regional augmentations (interconnectors) which have been capitalised after 1 July 1999 and were created under the provisions of clause 5.6.5 of the NEC.

Sunk Assets

“Sunk assets” are all existing assets which were in service prior to 1 July 1999. These assets were created under arrangements prevailing prior to operation of the NEC (although Queensland adopted the NEC as its jurisdictional code in 18 January 1998) and are treated as a special class under Clause 6.2.3 of the NEC.

New Assets

“New assets” include all new assets brought into service after 1 July 1999, other than “take or pay” and “clause 5.6.5” assets outlined above. This class would include all new intra-regional network assets as well as new non-network assets.

Because the revenue determination is being made in advance of the opening asset date, new assets (including “new assets” and “clause 5.6.5 assets”) will need to be further subdivided into assets capitalised and assets anticipated to be capitalised by the opening date. Based on an opening asset date of 1 July 2001 (for a 1 January 2002 revenue decision), these two such categories of new assets are:

- New assets capitalised – from 1July 1999 to 30 June 2000; and
- New assets anticipated – from 1July 2000 to 30 June 2001.

6.2.2 Valuation Principles

This section outlines the valuation principles which the NEC contemplates will be applied to each category of assets. In addition, this section also outlines the revaluation principles which the ACCC may apply in line with the NEC and the DRP.

Take or Pay Assets

As pointed out above, Powerlink does not have "take or pay" assets within its regulated asset base.

Clause 5.6.5 (Interconnector) Assets

Clause 6.2.3 (d) (4) (ii) prescribes that this class of asset be valued in a manner consistent with the respective network augmentation determinations made by NEMMCO under clause 5.6. Powerlink has a single project which falls into this class – the Queensland portion of the QNI. Because the QNI project was commenced at a point in time (1998) when NEMMCO did not have the legal status to conduct the NEC processes under clause 5.6, the ACCC categorised QNI as a regulated interconnector as part of its September 1998 National Electricity Market Access Code Decision.

QNI is now in service and most of the assets will be capitalised in the 2000/2001 year. The 275kV line between Tarong and Braemar, which forms part of QNI, has already been capitalised in the 1999/2000 financial year. Therefore, under the provisions of the NEC, these assets would be valued based on the project cost used in the determination under NEC clause 5.6.

Section 6.6 of this Application will include asset values capitalised in the 1999/2000 financial year relating to this particular class of assets.

Further, Powerlink has identified QNI as a project with significant capital savings/efficiencies which requires special consideration in accordance with DRP Principle S7.2. This is outlined in section 6.9.

Sunk Assets

The Queensland jurisdictional regulator (ERU) engaged independent consultants (Arthur Andersen) to undertake a full valuation of Powerlink's assets in service at 1 July 1999. The process is outlined in sections 6.3 and 6.4.

Powerlink has reviewed the asset values determined by Arthur Andersen and believes that some changes should be made to the ERU valuation. Section 6.5 outlines these changes.

New Assets

Section 6.6 of this Application details the value of new transmission assets, including the value of new interconnector assets (NEC Clause 5.6.5 assets), added to the regulated asset base in 1999/2000.

6.3 ODRC Principles

Assets included in Powerlink's database as at 1 July 1999 have been valued under the Optimised Depreciated Replacement Cost (ODRC) methodology which is supported by the ACCC under DRP Principle S4.2.

The process used to value Powerlink's assets using the ODRC principles is the sequential process of:

1. Identifying each element in the physical database that makes up the transmission network;

2. Assigning a replacement cost value to each of the identified elements on the basis of providing the same functional purpose with currently available technology;

3. "Optimising out" any assets from the physical database to remove any over capacity, over design and other inefficiencies of past decisions;

4. Depreciating the replacement cost value of the optimised asset base on the basis of the asset's age.

Powerlink's network assets are broken down into a number of asset classes as shown in Table 6.1. Each class has a standard life which is also used to determine the rate of depreciation applied.

Table 6.1. Standard lives for Network Assets

Asset Class		Standard Life
Substations	Establishment, buildings, bay primary plant	40 years
	Transformers, reactive plant	40 years
	Secondary systems	15 years
Transmission Lines	Steel tower & pole, concrete pole lines	50 years
	Wood pole lines	45 years
	Underground transmission cables	45 years
Communications	Buildings, towers, site infrastructure	40 years
	Other Communications assets	15 years
Network Switching Centre	Control centre systems	12 years
Easements	All easements	Infinite
Land	All land	Infinite
Commercial Buildings	All buildings	40 years
Houses	All houses	40 years

The asset classes subject to valuation using ODRC principles are substation, transmission line and communications assets.

6.4 Valuation by ERU at 1 July 1999

In October 1999 the Electricity Reform Unit, in its role as jurisdictional regulator, engaged Arthur Andersen, in conjunction with Worley International Ltd and Gutteridge, Haskins & Davey Ltd, to:

- Undertake an audit of data prepared by Powerlink in respect of quantities, systems and processes to ensure that the asset data has integrity and therefore that the asset valuation was valid;
- Determine standard costs, standard lives and standard modelling assumptions based on industry costs, interstate and commercial benchmarks;
- Advise on the appropriateness and consistency of the methodology being adopted for remaining life assumptions and other valuation related issues;
- Determine optimisation guidelines and apply these guidelines to calculate ODRC values for Powerlink’s assets as at 1 July 1999;
- Establish a formal certified ODRC valuation of the subject assets.

ERU used the Arthur Andersen valuation of Powerlink Queensland's regulated assets as at 1 July 1999 as the basis for determining revenue caps for Powerlink for the years 1999/2000, 2000/2001 and 2001/2002. This determination is detailed in Reference 6.

The independent valuation of Powerlink's regulated assets resulted in the ODRC valuation as at 1 July 1999 summarised in Table 6.2. It should be noted that the valuation of transmission line easements on a replacement cost basis by Arthur Andersen resulted in a value of $1.1billion. For revenue determination purposes, ERU adopted a value for easements based on acquisition costs, adjusted for inflation, of $114 million.

Table 6.2. ODRC Valuation of Regulated Assets as at 1 July 1999

Asset Class	Arthur Andersen Valuation		ERU Valuation	
	ORV	ODRC	ORV	ODRC
Substations	885,371,000	466,472,000	885,371,000	465,764,000
Transmission Lines	1,922,507,000	1,178,836,000	1,922,507,000	1,178,836,000
Communications	55,243,000	25,127,000	55,243,000	25,127,000
Network Switching Centres	0	0	0	0
Easements	1,099,059,000	1,099,059,000	114,397,000	114,397,000
Land	30,411,000	30,411,000	30,411,000	30,411,000
Commercial Buildings & Houses	22,803,000	12,343,000	22,803,000	12,343,000
Computer Equipment	20,376,000	4,836,000	20,376,000	4,836,000
Office Furniture & Misc	978,000	416,000	978,000	416,000
Office Machines	477,000	177,000	477,000	177,000
Vehicles	6,766,000	5,416,000	6,766,000	5,416,000
Moveable Plant	4,285,000	1,955,000	4,285,000	1,955,000
Insurance Spares	1,976,000	1,976,000	1,976,000	1,976,000
Total	**4,050,252,000**	**2,827,024,000**	**3,065,590,000**	**1,841,654,000**

Subsequent to ERU setting the three year revenue caps, Powerlink reset its financial asset register to align with the ERU 1 July 1999 valuation, and this is reflected in Powerlink's 1999/2000 Annual Report.

There were several aspects of this ERU valuation with which Powerlink believes require amendment.

6.5 Case for Amending the ERU Valuation

In the valuation of Powerlink assets carried out by Arthur Andersen for ERU, the value of substation, transmission line, communication, land and easements assets was determined using the optimised depreciated replacement cost (ODRC) approach. Non-network assets, which comprise less than 1.5% of the total asset base, were assigned their current written down financial book values.

At the time of the ERU valuation, Powerlink was given a very short time to review the Arthur Andersen valuation. While Powerlink was generally satisfied with the outcome of the valuation, there were elements of the ERU valuation with which Powerlink believed should be reviewed.

This review has concluded that the asset values (at 1 July 1999) should be approximately 8% above the values adopted in the ERU valuation. This adjustment is a result of:

- A detailed study which shows the appropriate values for Powerlink's 110kV and 132kV substation bay costs were valued too low;
- A detailed study which has identified an appropriate cost of financing during construction (FDC);
- A review of costs based on latest construction and material costs which has resulted in minor adjustments; and
- A detailed study to determine an appropriate transmission line easement valuation which represents an indexed Depreciated Actual Cost (DAC) approach (as an alternative to ODRC and current book value). The ACCC, at a recent asset valuation forum, indicated that an indexed DAC approach is considered the likely valuation approach it will apply rather than an ODRC valuation. Powerlink has undertaken a study which highlights that its current easement values are below an indexed DAC value.

Table 6.3 outlines the regulated asset values determined by Powerlink as a result of its recent review.

Table 6.3. Revised Regulated Asset Values at 1 July 1999

Asset Class		ERU Valuation @ 1 July 1999	Revised Values @ 1 July 1999	Difference ($)	Difference (%)
Substations	ORV	885,371,000	935,130,000	49,759,000	5.62
	ODRC	465,764,000	489,024,000	23,260,000	4.99
Transmission Lines	ORV	1,922,507,000	1,992,808,000	70,301,000	3.66
	ODRC	1,178,836,000	1,221,471,000	42,635,000	3.62
Communications	ORV	55,243,000	55,708,000	465,000	0.84
	ODRC	25,127,000	26,032,000	905,000	3.60
Network Switching Centres	ORV	0	0	0	0
	ODRC	0	0	0	0
Easements	ORV	114,397,000	198,074,000	83,677,000	73.15
	ODRC	114,397,000	198,074,000	83,677,000	73.15
Land	ORV	30,411,000	30,411,000	0	0
	ODRC	30,411,000	30,411,000	0	0
Commercial Buildings	ORV	22,516,000*	15,915,000	0	0
	ODRC	12,056,000	12,056,000	0	0
Houses	ORV	287,000	287,000	0	0
	ODRC	287,000	287,000	0	0
Computer Equipment	ORV	20,376,000	20,376,000	0	0
	ODRC	4,836,000	4,836,000	0	0
Office Furniture & Misc	ORV	978,000	978,000	0	0
	ODRC	416,000	416,000	0	0
Office Machines	ORV	477,000	477,000	0	0
	ODRC	177,000	177,000	0	0
Vehicles	ORV	6,766,000	6,766,000	0	0
	ODRC	5,416,000	5,416,000	0	0
Moveable Plant	ORV	4,285,000	4,285,000	0	0
	ODRC	1,955,000	1,955,000	0	0
Insurance Spares	ORV	1,976,000	1,976,000	0	0
	ODRC	1,976,000	1,976,000	0	0
Total	**ORV**	**3,058,989,000**	**3,263,191,000**	**204,202,000**	**6.68**
	ODRC	**1,841,654,000**	**1,992,131,000**	**150,477,000**	**8.17**

* Incorrect ORV shown in ERU valuation (Corrected value of $15,915,000 used in totals & comparisons)

6.6 New Assets & Interconnector Assets 1/7/1999-30/6/2000

The value for assets defined as “new assets” and “Interconnector assets” in section 6.2.1 are outlined below. The asset values listed are those regulated assets completed and commissioned (rolled into the asset base) between 1 July 1999 and 30 June 2000. The asset values include an allocation of financing charges as provided for in the ERU revenue determination.

Asset roll-in for the period 1 July 1999 to 30 June 2000 is recorded in Powerlink’s financial system (SAP) and has been audited as part of the 30 June 2000 annual financial statements

Table 6.4 shows the asset acquisitions (including financing during construction) and asset write-offs associated with regulated capitalised projects for the period 1 July 1999 to 30 June 2000.

Table 6.4. Regulated Asset Acquisitions and Write-offs for the 1999/2000 Financial Year

Asset Class	New Asset Acquisitions (inc FDC)	Interconnector (QNI) Asset Acquisitions (inc FDC)	Asset Write-offs	
			ORV	ODRC
Substations	55,144,741	5,801,431	4,816,421	1,165,733
Transmission Lines	70,247,869	44,422,896	0	0
Communications	8,418,568	0	917,347	306,702
Network Switching Centres	14,323,030	0	0	0
Easements	20,147,488	0	0	0
Land	2,832,665	0	2,886,266	2,886,266
Commercial Buildings	1,905,163	0	0	0
Houses	142,644	0	0	0
Computer Equipment	9,043,796	0	964,328	13,346
Office Furniture & Misc	0	0	0	0
Office Machines	1,294	0	0	0
Vehicles	2,472,763	0	2,324,173	1,688,099
Moveable Plant	203,638	0	0	0
Total	**184,883,659**	**50,224,327**	**11,908,535**	**6,060,146**

The Interconnector (QNI) asset acquisitions above include the construction cost of the Tarong-Braemar section of QNI. The QNI values need to be reconsidered as part of the review of capital/efficiency savings from the QNI project, as outlined in section 6.9.

6.7 Asset Valuation Rolled Forward to 1 July 2000

Not including any variations for efficiency savings from the QNI project (see section 6.9), Powerlink's regulated financial asset base rolled forward to 1 July 2000 is shown in Table 6.5.

Table 6.5. Regulated Asset Valuation Roll Forward to 1 July 2000

Asset Class		1 July 1999 "Sunk Assets"	Depreciation (inc. Write-offs)	Indexation	Asset Acquisitions	1 July 2000 Opening Value
Substations	ORV	935,130,000	4,816,421	20,572,863	60,946,172	1,011,833,000
	ODRC	489,024,000	27,458,626	10,180,080	60,946,172	532,692,000
Transmission Lines	ORV	1,992,808,000	0	43,841,781	114,670,765	2,151,321,000
	ODRC	1,221,471,000	40,300,522	25,985,746	114,670,765	1,321,827,000
Communications	ORV	55,708,000	917,347	1,225,585	8,418,568	64,435,000
	ODRC	26,032,000	2,023,136	534,932	8,418,568	32,962,000
Network Switching Centres	ORV	0	0	0	14,323,030	14,323,000
	ODRC	0	1,193,377	0	14,323,030	13,130,000
Easements	ORV	198,074,000	0	4,363,190	20,147,488	222,585,000
	ODRC	198,074,000	0	4,363,190	20,147,488	222,585,000
Land	ORV	30,411,000	2,886,266	669,042	2,832,665	31,026,000
	ODRC	30,411,000	2,886,266	669,042	2,832,665	31,026,000
Commercial Buildings	ORV	15,915,000	0	350,130	1,905,163	18,170,000
	ODRC	12,056,000	447,027	265,232	1,905,163	13,779,000
Houses	ORV	287,000	0	6,314	142,644	436,000
	ODRC	287,000	8,350	6,314	142,644	428,000
Computer Equipment	ORV	20,376,000	964,328	0	9,043,796	28,455,000
	ODRC	4,836,000	4,537,001	0	9,043,796	9,343,000
Office Furniture & Misc	ORV	978,000	0	0	0	978,000
	ODRC	416,000	122,788	0	0	293,000
Office Machines	ORV	477,000	0	0	1,294	478,000
	ODRC	177,000	45,836	0	1,294	132,000
Vehicles	ORV	6,766,000	2,324,173	0	2,472,763	6,915,000
	ODRC	5,416,000	2,343,634	0	2,472,763	5,545,000
Moveable Plant	ORV	4,285,000	0	0	203,638	4,489,000
	ODRC	1,955,000	463,393	0	203,638	1,695,000
Insurance Spares	ORV	1,976,000	0	0	0	1,976,000
	ODRC	1,976,000	0	0	0	1,976,000
Total	**ORV**	**3,263,191,000**	**11,908,535**	**71,028,905**	**235,107,986**	**3,557,419,000**
	ODRC	**1,992,131,000**	**81,829,954**	**42,004,536**	**235,107,986**	**2,187,414,000**

6.8 Asset Roll Forward from 1 July 2000 – 30 June 2001

The 1 July 2000 revalued regulated asset base needs to be rolled forward to 1 July 2001, to establish the opening value of the ACCC revenue reset period.

This roll forward takes into account:

- expected new additions (roll-in) in the period;
- expected disposals in the period;
- anticipated depreciation for the period;
- anticipated asset indexation for the period;
- adjustment for QNI efficiency savings from section 6.9.

This roll forward is summarised in Table 6.6 below;

Table 6.6. Regulated Asset Value Roll Forward to 1 July 2001

	Regulated Asset Value ($'000)	
	ORV	ODRC
Opening Regulated Asset Value – 1 July 2000	3,557,419	2,187,414
Depreciation (inc. Write-offs) – 1 July 2000 to 30 June 2001	0	(88,804)
Indexation – 2000/2001	87,849	52,201
New Acquisitions – 1 July 2000 to 30 June 2001	114,202	114,202
Interconnector Acquisitions – 1 July 2000 to 30 June 2001	205,276	205,276
Opening Regulated Asset Value – 1 July 2001	3,964,746	2,470,289

6.9 Interconnector Efficiency Savings

The Queensland portion of the Queensland – New South Wales Interconnector (QNI) project cost estimate, which was determined by an independent consultant, and was used for the basis of the ACCC authorisation as a regulated interconnector, is $270M (at June 2000 cost levels) and includes interest during construction.

Powerlink has reviewed this project estimate and considers the project can be completed for $255.5M (including FDC) based on a conventional project management approach. This estimate has been used in the asset roll forward outlined in section 6.8 above.

Powerlink has taken a more innovative approach to project management, and as a result, is expecting to produce $40.5M in project savings. These management induced efficiency gains include:

- ❖ Capital savings of $18.5M from management induced efficiency gains associated with transmission line route acquisition;
- ❖ Capital savings of $6M from management induced efficiency gains associated with selection of the transmission line contractor;
- ❖ Capital savings of $6.5M from management induced efficiency gains associated with hedging of aluminium prices;
- ❖ Capital savings of $2.6M from management induced efficiency gains associated with 100% use of imported structural steel;
- ❖ Capital savings of $6.9M from management induced efficiency gains associated with innovative project management.

In its Draft Statement of Regulatory Principles, the ACCC has stated that *"The TNSP is invited to demonstrate in its regulatory review that any capital expenditure below forecast levels over the previous regulatory period has arisen from management induced efficiency gains. Where it is clearly demonstrated by the TNSP that capital expenditure shortfalls are a result of management efficiencies or innovation, the capital expenditure efficiency gains may be subject to a glide path."* (Principle S7.2).

This principle reflects the underlying philosophy of the ACCC's incentive-based regulation regime viz. that TNSPs are to be encouraged to pursue efficiencies by being able to retain a reasonable share of the benefits from these efficiencies.

The Queensland portion of the Qld-NSW Interconnector represents an ideal example for the demonstration of this principle:

- ❖ The capital cost for each portion (QLD – NSW) of the Interconnector was estimated by an independent specialist consultant;
- ❖ The actual cost of the Queensland portion is significantly less than the independent estimate.

Powerlink has identified and quantified $40.5M of capital savings which have arisen from management induced efficiency gains. Powerlink believes that, in an incentive-based regulatory regime, it should be entitled to benefit from those efficiency gains.

This $40.5M capital saving has been included in the regulated asset roll forward outlined in section 6.8.

6.10 Summary of Regulated Asset Base Values

The value of Powerlink's Regulated Asset Base as at 1 July 2001 has been derived from:

- An independent valuation undertaken by the jurisdictional regulator as at 1 July 1999;
- Adjustments which Powerlink believes need to be made to that valuation as outlined in section 6.5;
- The roll-forward of that valuation to 1 July 2000, based on capex, depreciation and revaluation (which were audited as part of Powerlink's 1999/2000 financial reports);
- Interconnector efficiency savings as outlined in Section 6.9;
- A roll-forward to 1 July 2001 based on <u>projected</u> capex, depreciation and revaluation.

A summary of the values to be used in the roll forward from 1 July 1999 to 1 July 2001 is shown in Table 6.7 below:

Table 6.7. Regulated Asset Roll Forward from 1 July 1999 to 1 July 2001

	Regulated Asset Value ($'000)		
	1999/2000	2000/2001	2001/2002
Regulated Opening Asset Value – 1 July	1,992,131	2,187,414	2,470,289
Depreciation (inc. Write-offs)	(81,830)	(88,804)	
Indexation	42,005	52,201	
New Acquisitions	235,108	319,478	
Regulated Closing Asset Value – 30 June	2,187,414	2,470,289	

The Regulated Asset Base opening value for 1 July 2001 used in the revenue cap determination should be $2,470.3M.

7 Capital Expenditure

7.1 Introduction

As a transmission network service provider (TNSP), Powerlink is obliged to meet the requirements of Schedule 5.1 of the National Electricity Code (NEC) and in particular, clause S 5.1.2.1:

> *"Network Service Providers must plan, design, maintain and operate their transmission network … to allow the transfer of power from generating units to Customers with all facilities or equipment associated with the power system in service and may be required by a Code Participant under a connection agreement to continue to allow the transfer of power with certain facilities or plant associated with the power system out of service, whether or not accompanied by the occurrence of certain faults (called "credible contingency events").*
>
> *The following credible contingency events and practices must be used by Network Service Providers for planning and operation of transmission networks…*
>
> *The credible contingency events must include the disconnection of any single generating unit or transmission line, with or without the application of a single circuit two-phase-to-ground solid fault on lines operating at or above 220 kV."*

Powerlink's transmission authority also includes a responsibility

> *"… to ensure as far as technically and economically practicable, that the transmission grid is operated (and if necessary, augmented or extended to provide enough capacity) to provide network services to persons authorised to connect to the grid or take electricity from the grid …"* (Electricity Act 1994, S34).

These obligations give rise to an ongoing program of capital expenditure to develop the grid and to replace aged assets.

In addition to this security-driven capital expenditure, TNSPs are also required under clause 5.6 of the NEC to determine where network constraints and losses should be reduced by augmenting the network if this satisfies the Regulatory Test.

It needs to be made clear that the aim of estimating capital expenditure in the revenue setting process is NOT for the ACCC to give approval to the TNSP for new network projects. Under the NEC, the TNSP is required to follow specific procedures (including the *Regulatory Test*) for each project at the time the TNSP wishes to advance that particular project. Rather, the aim of this submission is to estimate the capex requirements during the regulatory period so that the TNSP's revenue cap includes an appropriate allowance to enable it to meet network developments driven by the National Electricity Code, Electricity Act and transmission licence obligations.

7.2 Dealing with Uncertainty

With the arrival of significant new committed generation capacity in Queensland over the next few years, there is considerable uncertainty about the generation patterns which will emerge, and consequently about the network developments required to meet the continuing high load growths in Queensland.

Indeed, there are many plausible scenarios for the emerging generation patterns and hence for network developments.

Recognising this unique set of circumstances, Powerlink provided the ACCC with a discussion paper (Reference 1) which outlined both the nature of the capex forecasting challenge and a proposed approach. At the suggestion of the ACCC, Powerlink subsequently held a public forum (November 2000) on its proposed approach and invited Queensland market participants and interested parties, who where also given the opportunity to subsequently comment in writing to Powerlink and the ACCC on the proposed approach. The forum was well attended. The feedback on the day and in later submissions was supportive of Powerlink's approach.

Powerlink has therefore developed the capex forecast presented in Section 7.3.6 using the probabilistic approach as outlined in that discussion paper.

The capex forecast developed in this Application relates only to future *regulated* services and assets.

7.3 Powerlink's capex forecast

7.3.1 The process

As outlined in Reference 1, to forecast future capital expenditure, a transmission network service provider (TNSP) estimates the cost of what is predicted to be the required future transmission augmentations (new works) and replacements of aged/obsolete plant and equipment, including plant whose service rating is, or will be, exceeded.

Figure 7.1 illustrates the variables that influence the decision-making process.

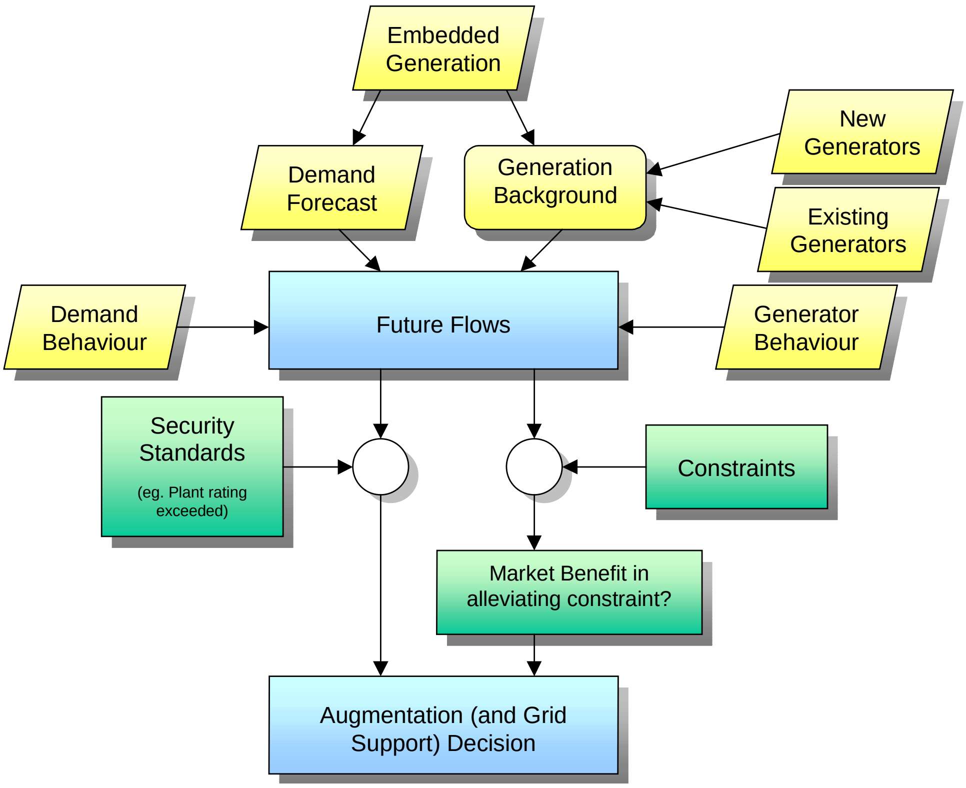


Figure 7.1. Principal factors which drive network augmentations

For a single assumed demand forecast and a single pattern of generation dispatch, the future flows on the transmission system can be estimated using a combination of wholesale market modelling and transmission network analysis techniques.

These network power flows are then analysed for compliance with the NEC security and reliability standards which Powerlink is obliged to meet. An augmentation is identified where the analysis highlights a shortcoming in network capability. These augmentations can include Grid Support options.

This process is repeated for each plausible scenario for future patterns of generation dispatch and demand forecast. The outcome is a range of plausible augmentations and associated capital expenditures.

7.3.2 Load forecasts

In accordance with clause 5.6.1 of the NEC, Powerlink obtains demand forecasts over a ten-year horizon from Distribution Network Service Providers (DNSPs) and customers at each connection point in Powerlink's transmission system.

Aggregate demand forecasts are also estimated for the total Queensland region and for each of nine newly defined zones in Queensland (as defined in Powerlink's *2000 Annual Planning Statement* – Reference 7), derived from the individual connection point forecasts using diversity factors observed from historical records up to the 1998/99 financial year.

Powerlink also engages the services of the National Institute of Economic and Industrial Research (NIEIR) to provide an independent assessment of energy and demand forecasts for the Queensland region and for each DNSP service area. NIEIR also provides economic outlook analysis for the high and low growth scenario forecasts. These economic scenario variations correspond to those provided by NIEIR to NEMMCO for its Statement of Opportunities.

Powerlink publishes the resulting demand forecast in its Annual Planning Statement. The demand forecasts assumed for the scenarios used to forecast capital expenditure are as published in Powerlink's *Annual Planning Statement 2000* (Reference 7) and illustrated in Figure 7.2.

It is notable that this latest forecast includes predictions, provided by NIEIR, of significant growth in new cogeneration and renewable energy source generation projects driven by the 2% renewables policy. The NIEIR predictions include significantly more such generation developments than the small number of currently committed embedded generation developments that were identified in the forecasts provided to Powerlink by the DNSPs.

It would appear that the actual rate of growth in off-grid generation may be lower than the predictions and hence the rate of growth of grid-transported energy may be higher than predicted in the Annual Planning Statement. In addition, there is even greater uncertainty with the seasonality of new cogeneration, in particular whether new cogeneration using sugar mill bagasse as a fuel will generate over the peak summer load periods or only during the cane-crushing season. Nonetheless, we have used the (probably conservative) predictions of growth of grid-transported energy predicted in the Annual Planning Statement.

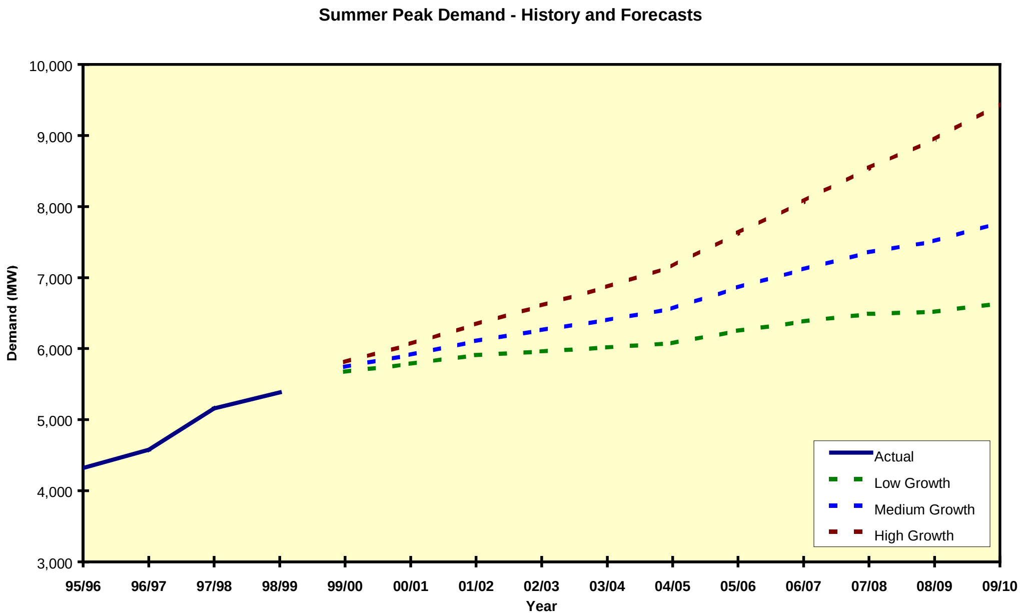


Figure 7.2. Load Forecast

7.3.3 Generation forecast

Powerlink engaged specialist consultants, ROAM Consulting, to conduct wholesale market modelling in order to identify the plausible generation patterns for Queensland over the next 10 years.

ROAM Consulting developed a total of 72 plausible scenarios and the relative probability of occurrence of each scenario.

The 72 scenarios result from a consideration of four major themes:

Table 7.1. Probabilistic scenario themes

Possible Outcome	Notes
Queensland Energy Policy – outcomes vs expectations	
Outcomes lower than expectations	At 2005, less than 3 major gas-fired plants are in operation.
Outcomes equal expectations	At 2005, 3 major gas-fired plants are in operation.
Outcomes exceed expectations	At 2005, more than 3 major gas-fired plants are in operation.
Load Growth	
Low load growth	As in the Annual Planning Statement 2000
Medium load growth	As in the Annual Planning Statement 2000
Medium load growth with added new loads	Included in this scenario is an additional load for the following projects: • A 300MW allowance for AMC magnesium project; • A 100MW allowance for Korea Zinc stage 2
High load growth	As in the Annual Planning Statement 2000
Kyoto targets – outcomes vs expectations	
Outcomes lower than expectations	Less than 6 combined cycle generators are operating in Queensland by 2010.
Outcomes equal expectations	6 combined cycle generators are operating in Queensland by 2010.
Outcomes exceed expectations	More than 6 combined cycle generators are operating in Queensland by 2010.
Impact of Committed New Coal-based Generation	
Low impact	In this theme, it is assumed that the new coal plant will win market share slowly.
High impact	In this theme, it is assumed that the new coal plant will win market share quickly.

The 72 scenarios result from the 72 possible combinations of outcomes from the above themes (i.e. 3x4x3x2).

Figure 7.3 shows the probabilities of the 72 scenarios as estimated by ROAM Consulting. It is notable in this graph that no scenario has a probability greater than 8%, highlighting the significant uncertainty.

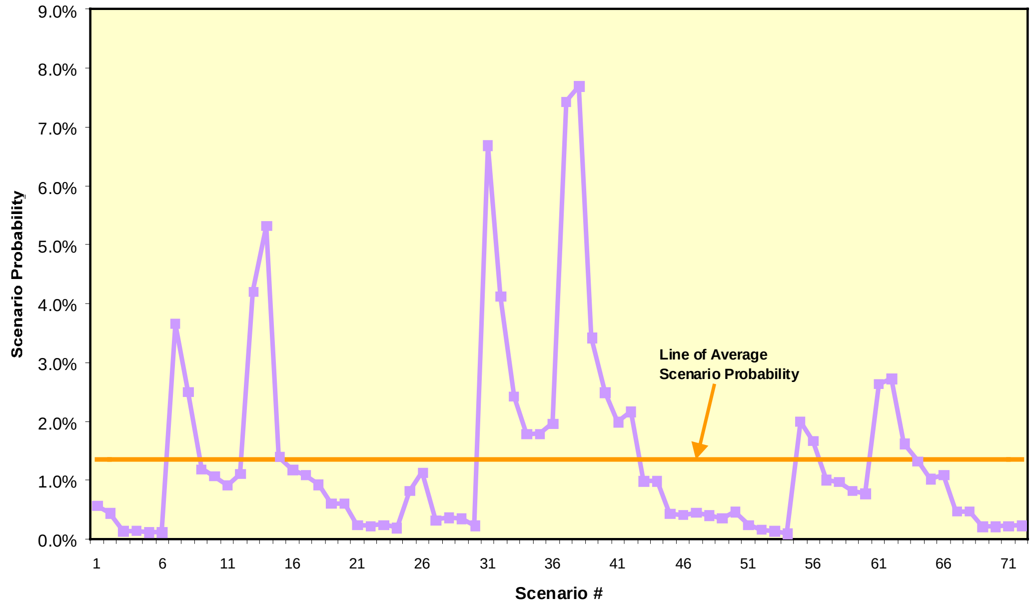


Figure 7.3. Scenario Probabilities

7.3.4 Transmission plans

For each scenario, proven transmission planning techniques were used to identify a set of augmentations (a *transmission plan*) to ensure compliance with NEC and other requirements. The 72 input scenarios thus resulted in 72 transmission plans.

It is to be noted that there is a 2 to 4-year lead time in transmission augmentation projects. We have consequently developed capex forecasts up to 2010 to ensure that the effects immediately beyond this regulatory period are transparent. These transmission plans do not include any non-regulated network investments Powerlink may seek to undertake in the future.

7.3.5 Estimates of Project Costs

Powerlink has developed and maintains a comprehensive database of capital costs for all types of transmission projects. These include a range of transmission lines, both single and double circuit, for various structure types and operating voltages, as well as basic modular elements of substations at various voltages. The majority of these costs are based on recent competitive tendering outcomes, but also take into account such influences as inflation rate, exchange rate movements, international metal prices and other market factors such as demand for particular contract services. This database is continually updated to reflect new information and, given that Powerlink has undertaken, or has committed to, about $1 billion of capital expenditure over the past 5 years, this information is particularly robust. The capital estimates used in the capital forecasts are derived from this database.

Transmission capital projects incur costs progressively as the project is constructed. In order to account for the total completed project costs, financing costs during the construction period (FDC) also need to be included. These costs represent the finished cost of the project if it were constructed turnkey with payment settled upon completion. Financing costs comprise of two components (illustrated in Figure 7.4):

- ❖ Finance charges up to the point of completion of the project and
- ❖ Finance charges from completion (commissioning) to the point where a return on capital is allowed under the accrual building block approach.

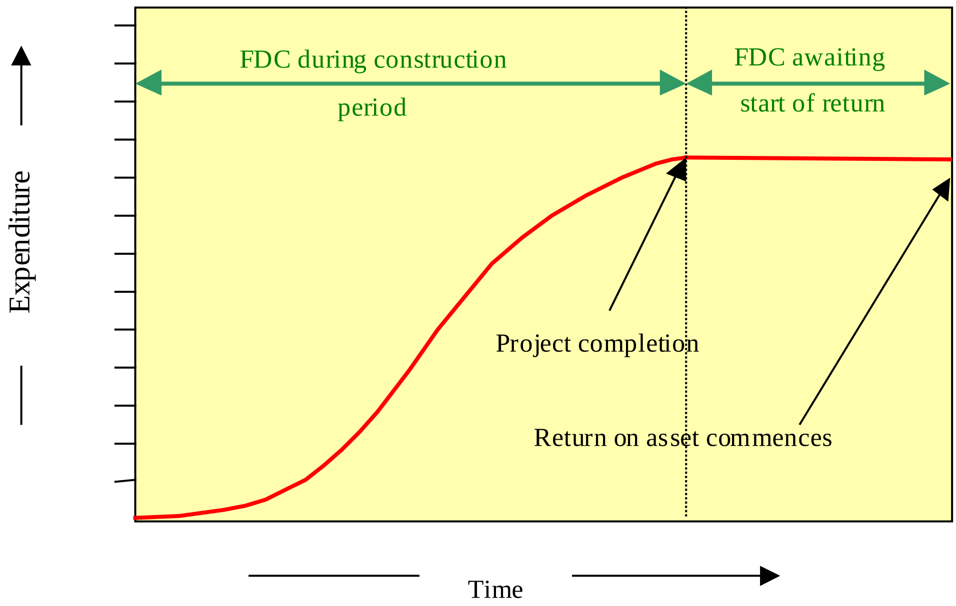


Figure 7.4. Illustration of financing costs

The first financing charge, which is purely construction related, will be considered later within this chapter of the Application. The second portion of the financing charge is dealt with in Chapter 10 of this Application as it relates purely to the return component of the revenue calculation.

The above financing costs are often referred to (incorrectly) as IDC – interest during construction. However, in reality, these costs also include an equity component as well as a debt finance component and will be referred to as FDC (Finance costs During Construction) in this Application.

7.3.6 Probabilistic Capex Outcomes

Figure 7.5 shows the annual regulated capex profile which results from each of the 72 scenarios (expressed in 2000/01 price levels). The red dotted traces shows the envelope of expenditure while the solid red trace shows the *expected capex requirement* (being the probability weighted average of the 72 scenarios). The probability that is attributed to each transmission plan is that of the input scenario from which it was derived.

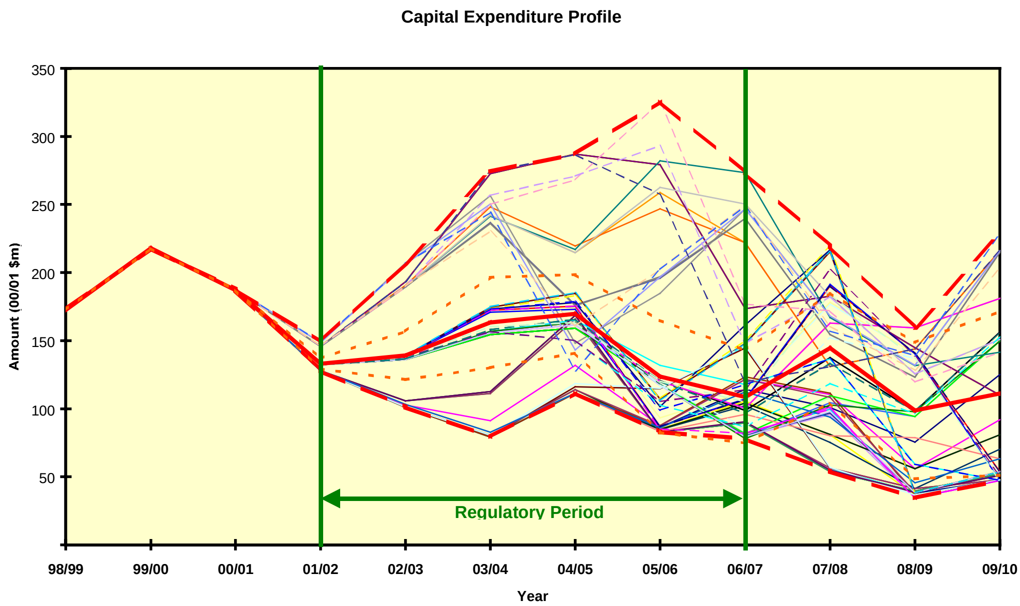


Figure 7.5. Regulated Capital Expenditure Profile

The following table lists the numerical values of the expected capex requirement (excluding allowable financing costs):

Table 7.2. Expected regulated capex requirement (excluding allowable financing costs)

($m, Nominal)	01/02	02/03	03/04	04/05	05/06	06/07
Network Capex	124.3	136.9	166.3	173.7	129.8	112.6
Non-network Capex	12.1	9.2	9.6	13.6	10.1	13.4
Total Forecast Capex	**136.4**	**146.1**	**175.9**	**187.3**	**140.0**	**126.1**

The annual average for the 5-year period 2002/03 to 2006/07 is $155 million which can be shown (in Section 7.3.8) to be reasonable given the size and age of the network and the expected load growth.

The same information can be viewed in a cumulative expenditure profile, as shown in Figure 7.5. Presenting expenditure cumulatively tends to damp the timing differences of annualised expenditures. This cumulative approach allows confidence levels of expenditure to be more readily illustrated.

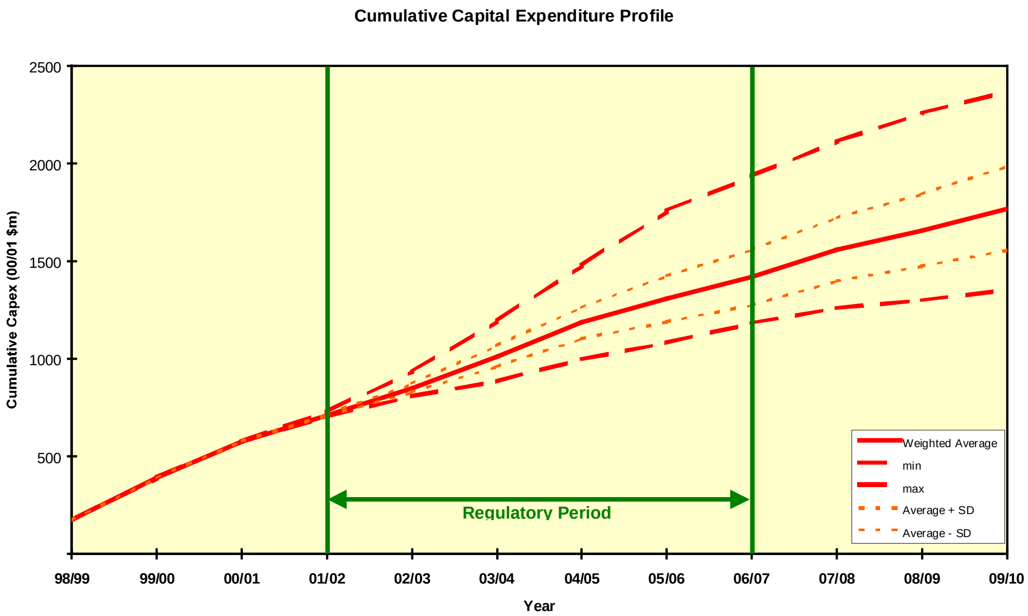


Figure 7.6. Cumulative Regulated Capital Expenditure Profile

Consistent with the Statement of Regulatory Principles, capex is introduced into the asset base in the year that associated projects are commissioned. In a probabilistic treatment, this is equivalent to determining the asset roll-in for each scenario and calculating the *expected* asset roll-in as the probability-weighted average in the usual way.

Financing during construction (FDC) has been included in the capitalised values up to the point of project completion (commissioning) in Table 7.3 as follows:

- Transmission line works 7.6%
- Substations works 7.6%
- Communications Equipment works 2.0%
- All other works 0.0%

The above allowances for FDC have been derived by external consultants and are based on time-expenditure profiles for typical transmission investment works. No allowance has been made for FDC for the period from asset commissioning until the admission to the regulated asset base for the purposes of calculating a return on capital. This is discussed further in Section 10.4.

Table 7.3 summarises the amounts (in nominal terms) to be introduced into the asset base.

Table 7.3. Commissioned capex to be rolled into the asset base

($m, Nominal)	01/02	02/03	03/04	04/05	05/06	06/07
Lines (including easements)	33.3	32.8	83.3	105.6	102.1	12.9
Substations (including Comms)	93.5	117.9	74.9	86.8	66.0	56.8
Other Network	0.6	1.0	0.5	1.1	1.4	0.3
Non-network	12.1	9.2	9.6	13.6	10.1	13.4
Financing during construction (FDC)	9.1	10.6	11.6	14.1	12.6	5.1
Asset Roll-In	**148.6**	**171.5**	**180.0**	**221.2**	**192.1**	**88.6**

7.3.7 Grid Support

A number of transmission plans include, as an integral part of the plan, non-network grid support options, such as local generation as anticipated in clause 5.6.2 of the NEC. Specifically, a generation grid support option has been included when:

1. a generator exists in an area which is a generation-deficient area; and

2. security standards would be violated in the area only if the generator was offline or operating below maximum capacity; and

3. contracting for sufficient generation output is likely to be economic compared with a transmission reinforcement.

The above conditions exist for a number of years in some scenarios where constraining on a generator “buys time” until an expected new entrant connects to the network. In particular, certain transmission plans include obtaining grid support from generation sources in both North Queensland and South Queensland.

The estimated cost of the grid support payments to such generation sources is included in the proposed operating costs allowance in Section 8.7.4.

7.3.8 Reasonableness Test for the Capex Estimate

Whilst it is recognised that transmission capex is typically lumpy, an estimate of the long run average capex can be derived from the size of the network (asset value), the life of the assets and the forecast annual load growth.

Capex is needed to meet 2 requirements:

a) Replacement of existing assets which reach the end of their useful lives; and

b) Network augmentation to meet load growth.

The optimised replacement value (ORV) of Powerlink Queensland's network (excluding easements and land) at 1 July 2000 is $3,304M. The average life of assets is about 40 years, and the projected growth in Queensland is 3.5% pa.

Thus, capex (a) – replacement – can be approximated as $3,304M divided by 40 years i.e. $83M per annum.

Capex (b) – augmentation – can be approximated as $3,304M multiplied by 3.5% (demand growth) multiplied by a factor (<1.0) which assumes that some of the load growth is met by options other than regulated transmission network augmentations (eg local generation).

Assuming that 75% of demand growth is met by network options, then capex (b) is about $87M per annum.

This would result in a total average capex of $170M per annum.

Given the approximate nature of the calculation, this average is consistent with the annual average capex of $155M in Powerlink Queensland's figures for the 5-year period 2002/03 to 2006/07 (Section 7.3.6).

Thus, the capex can be regarded as "reasonable".

7.3.9 Adjustments for Actual Capex

Due to the uncertainties associated with forecasting future capital expenditure requirements within Powerlink's network there needs to be an arrangement in place whereby Powerlink's revenues are adjusted to reflect actual capex.

In order to minimise the impacts of price shocks which would occur should a one-off ex post adjustment be made at the end of the regulatory period, Powerlink proposes that an adjustment be made midway through the regulatory period (for the January 2002 – July 2005 period). Powerlink proposes a formularised approach be adopted in which: -

1. adjustment is based on the difference between the actual (including efficiency adjustments) and forecast capex roll-in (adjusted for FDC);
2. the adjustment be based on the cumulative capex difference multiplied by (WACC + economic depreciation);
3. an adjustment only be made if the cumulative difference between actual and estimated capex exceeds 5% of the estimated quantity.

7.3.10 Capital Contributions

At its formation in January 1995, Powerlink was assigned its transmission asset base without any recognition of capital contributions made to the vertically integrated Queensland electricity system prior to that date. The same arrangement applied to the Distribution network owners. Once roll out of retail contestability was commenced in early 1998, there was a recognition by the Queensland Electricity Reform Unit (QERU) that certain customers who had made a prior capital contribution (to gain access to standard tariffs) would now pay a full TUOS, including a return component, relating to assets to which they had previously contributed capital.

QERU therefore introduced a policy by which such customers who were now required to pay full TUOS (and DUOS) were eligible for a refund of the unexpired value of their original capital contribution, as determined by QERU. Whilst Powerlink will be continuing to pay these refunds over future years, Powerlink accrued the NPV of these future payments as an abnormal item in its accounts for the 1997/98 and 1998/99 financial years.

Since January 1995, no new capital contributions have been made by customers towards regulated assets.

Accordingly, there are no assets in the Regulated Asset Base which are now funded by capital contributions and which therefore require special consideration under Clauses 6.6.2 and 6.6.3 of the NEC.

7.3.11 Summary of Capex

Forecast regulated capital expenditure and asset roll-in for the regulatory period, as determined from the probabilistic approach outlined in this chapter is summarised in Table 7.4 below. The asset roll-in includes FDC up to the date of project completion.

Table 7.4. Summary of regulated capital expenditure

($m, Nominal)	01/02	02/03	03/04	04/05	05/06	06/07
Capex	136.4	146.1	175.9	187.3	140.0	126.1
Asset roll-in (including FDC)	148.6	171.5	180.0	221.2	192.1	88.6

8 Operating and Maintenance Expenditure

8.1 Introduction

The accrual building block model used to calculate annual revenue caps includes, as an input, an allowance for efficient operating expenses (opex). As part of this Application, Powerlink has developed an annual regulated opex requirement for each year of the regulatory period. The following approach was used to develop the opex allowances:

1. **Derive a base opex budget**
2. **Demonstrate the base opex budget is efficient**
3. **Project the base opex forward to provide for each regulatory year**
4. **Identify and target future efficiencies**

It should be noted that depreciation is **not** included in opex but is dealt with separately in Chapter 9.

8.2 Summary

International benchmarking shows that Powerlink is the most cost-efficient transmission entity in Australia and one of the most cost-efficient in the world, despite the significant disadvantages of a geographically-dispersed service territory.

By way of comparison, Powerlink's controllable operating costs in 1999/2000 were 2.4% of transmission asset value (ODRC) compared with the Australian/NZ average of around 4.2% (range 2.4% to 6.2%).

Whilst replacement asset value (rather than ODRC) is a better measure for the size of the operating and maintenance task, ODRC values have been used in comparisons between transmission entities because, unlike replacement value, ODRC value is readily available from sources such as Annual Reports.

In Powerlink's case, an operating costs ratio of 2.4% of the ODRC value equates to 1.7% of *replacement* value of network assets. On a replacement asset value basis, Powerlink's total operating costs have declined from 2.2% of transmission asset value in 1996/97 to 1.7% in 1999/2000 – a reduction of 7.2% per year. These reductions have been due to a combination of effectively harnessing economies of scale as the network expanded and applying operational and maintenance efficiency initiatives identified from active participation in international benchmarking.

Our projections are for the underlying operating costs (based on present activities) to decline further to 1.6% of transmission asset replacement value by the end of the first regulatory period (2006/07). This represents an annualised reduction of 0.8%, which is lower than the past reductions, due to:

- ❖ The need, demonstrated by benchmarking results, to increase maintenance costs, especially on refurbishments, in order to move to a higher reliability point on the costs / reliability tradeoff matrix.
- ❖ The offsetting impacts of diseconomies of geography. Most of Powerlink's recent major network additions are located away from the existing assets and the existing maintenance support centre/depot. This results in higher maintenance costs in the form of travel time and costs.
- ❖ The major gains already achieved over recent years:
  - ♦ maintenance crews already start on the job rather than come to a depot;
  - ♦ consolidation to a single depot in South East Queensland and the closing down of other depots;

- consolidation of three network switching centres throughout the State to a single centre;
- 70% of maintenance work is outsourced and the internal service provider is as efficient as the external providers;
- the "one-off" step reduction in administrative costs by relocating to a lower-cost non-CBD location.

In addition to the underlying operating costs, there are cost increases imposed by the NEM and its agencies:

- the administrative costs of the NEC process for large and small network augmentations;
- having to fund Market System Operator functions from TUOS rather than via NEMMCO market fees. In addition, Powerlink will have to undertake more Market System Operator functions than presently funded by NEMMCO;
- the increasing costs of insurance arising from the ongoing removal of statutory protections on liability.

Finally, there is a new cost component to cover Contracted Services, such as grid support services obtained from generators under the provisions of the NEC.

8.3 Powerlink's Business Model

Powerlink has adopted an Asset Manager / Service Provider business model for managing its business. The Asset Manager / Service Provider model segregates the purchasers of goods and services from the providers of those services (both internal and external). The purchaser (Asset Manager) sets the standards for the services required and pays all providers of goods and services at commercial rates[6]. The Asset Manager focuses on only procuring those services which add value to the network, whereas the Service Providers focus on efficient delivery of the service.

[6] See Section 5.2 for more discussion on the Asset Manager / Service Provider model – particularly regarding cost allocation.

Separating the service providers from the purchasers not only facilitates clear cost allocation between regulated and non-regulated business activities but it also encourages internal service providers to focus on delivery efficiency. The Asset Manager / Service Provider model does not distinguish between internal and external service providers. This has the effect of focusing on functions rather than the traditional organisational structure. The choice of service provider is a strategic decision based on optimising the cost of performing the function. This structure provides flexibility in resourcing support functions. By way of illustration, maintenance on Powerlink's network assets is performed by an internal business unit (for South East Queensland) and an external service provider (for the remainder of the service territory) whose performances are benchmarked. This has yielded significant cost efficiencies in the delivery of maintenance services.

8.4 Components and Drivers of Operating Expenditure

Opex can be disaggregated into a number of components, each with different cost drivers and different opportunities for efficiencies:

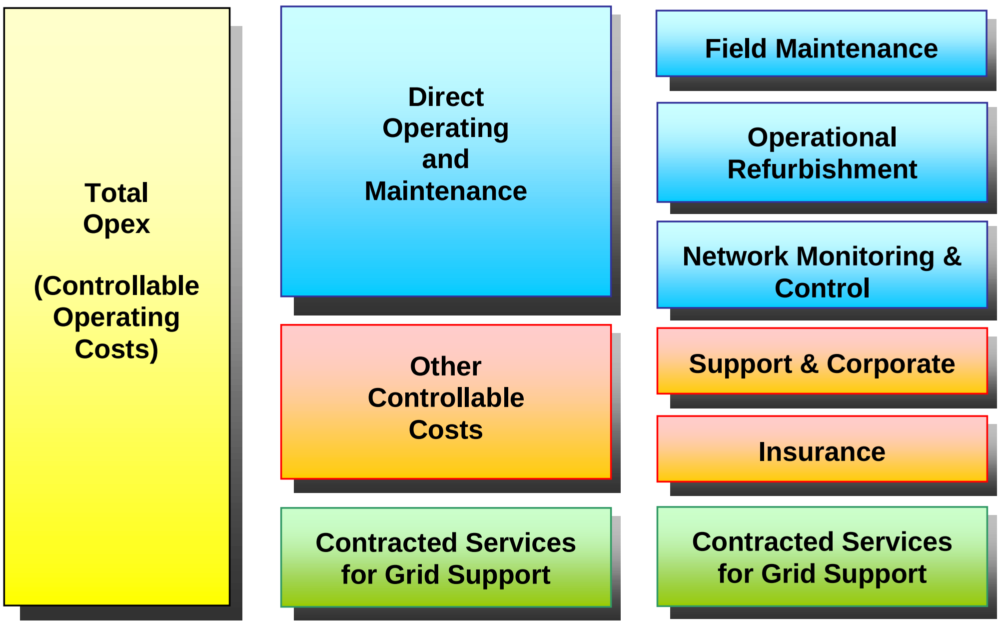


Figure 8.1. Components of Opex

The two major components of opex are:

- ❖ Direct operating and maintenance costs
- ❖ Other controllable costs

These exhibit different behavioural characteristics and drivers – the former shows minimal benefits from economies of scale; the latter shows more significant benefits from scale economies.

8.4.1 Summary

Direct Operating and Maintenance Costs

The costs of maintaining the network are driven by the amount of assets to be maintained, their age and condition and their geographical dispersion.

As the network grows, there will be more assets to maintain and hence direct maintenance costs can be expected to increase. There are minimal economies of scale in these costs, and indeed can be diseconomies of geography if the new assets are located away from the existing asset base. Thus, these costs grow with growth in network assets.

Efficiencies arise from changes in maintenance strategies (eg. using more condition-based techniques) and changes in work practices (eg starting work on the job site rather than at the depot, use of helicopters, etc) which are typically identified via international benchmarking with other transmission entities and other international forums (eg. CIGRE).

Future outlook: The latest benchmarking shows that Powerlink is already very efficient, having implemented efficiency measures identified in earlier benchmarking. There is minimal scope for further efficiency gains. Indeed, the benchmarking suggests that Powerlink should now focus on improving reliability by spending more on operational refurbishment.

Other Controllable Costs

These include the corporate, administrative, planning and engineering support costs for the business.

The cost drivers are quite different to those for direct maintenance costs. These support costs benefit from economies of scale and will increase at a much slower rate that the growth in network assets.

Efficiencies arise from "one-off" initiatives (eg a step decrease due to relocating the office from the high-cost CBD to a lower-cost non-CBD location) and from investment in modern business computing systems (which allow more network assets to be managed with minimal increases in corporate and administrative staff).

Future outlook: As Powerlink has already undertaken the key initiatives such as office relocation and implementation of modern, fully integrated business computing systems, there are minimal opportunities for efficiency gains in these costs. However, the Powerlink systems will allow some economies of scale to continue to be harnessed as the asset base grows.

8.4.2 Sub-components of Direct Operating and Maintenance Costs

Field Maintenance

Maintenance includes all actions required to retain an item of plant in, or restore it to, a state in which it can perform its required functions. Powerlink's assets are maintained through three mechanisms:

1. Regular (routine) maintenance according to pre-determined maintenance cycles;

2. Condition-based maintenance is a form of preventive maintenance performed when the monitored condition of equipment indicates that it requires maintenance;

3. Corrective maintenance performed to restore a failed component to an operational state.

Powerlink's Network Maintenance Business Unit maintains the network in the South East Region. Powerlink has a Service Level Agreement (SLA) with an external service provider, Ergon Energy, to perform maintenance in the remainder of the service territory (north of Bundaberg). Figure 8.2 below illustrates the maintenance areas serviced by Powerlink's Network Maintenance

Business Unit and Ergon Energy under the SLA. All service providers operate in accordance with Powerlink maintenance policies, procedures and work instructions.

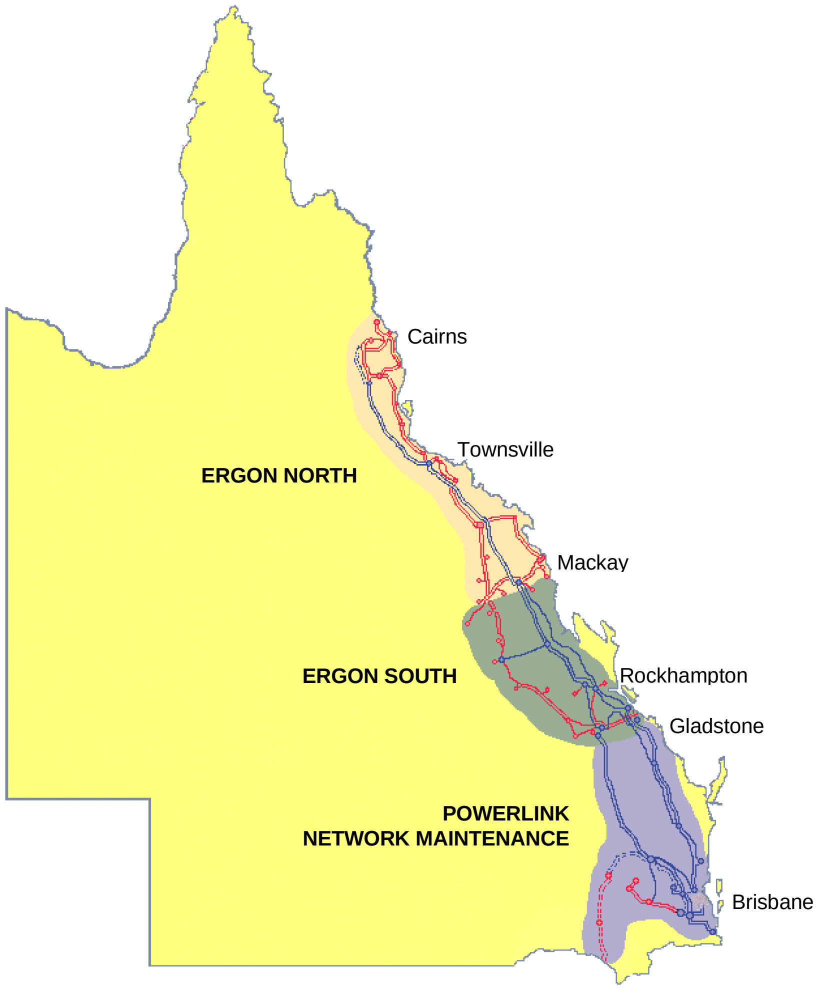


Figure 8.2. Maintenance Service Areas

Maintenance and Operating Strategies

The maintenance and operating strategies have two components. These are:

1. The Plant Management Strategy ("doing the right thing")

2. The Work Management Strategy ("doing the thing right")

To be truly world class, it is necessary to have both the optimal maintenance and operating policies ("doing the right thing") as well as the best work practices for implementing them ("doing the thing right").

Plant Management strategies are developed and reviewed to obtain maximum effectiveness by setting the maintenance and operating criteria to obtain the best performance from the plant. The Plant Management Strategy is documented in the Policies, Procedures, Work Instructions and Secondary Documents of the Maintenance and Operating sections of the Asset Manager Standards. These standards are developed using techniques such as Reliability Centered Maintenance, Whole of Life Cycle Costing and Quantitative Risk Assessment.

Work Management strategies are developed and reviewed to obtain maximum efficiency of implementation of the Plant Management Strategy. A constant pressure for improved performance is maintained. This is achieved by participating in national and international benchmarking, and by structuring Service Level Agreements to be performance-based. A constant watch is kept on new developments, and new techniques (for example, use of helicopters) are introduced when appropriate.

From a regulatory point of view, the **efficiency** of Work Management strategies can be evaluated through benchmarking of costs while the **effectiveness** of Plant Management strategies is evident through benchmarking service standards. Clearly, there is always a tradeoff between costs (efficiency) and service standards (effectiveness), and the objective is to obtain the right balance between the two. It is customary to view benchmarking results as a cross-plot of costs (efficiency) against service standards (effectiveness) to assess this balance.

Operational Refurbishment

Often components or sub-assemblies of plant have lesser working lives than does the primary asset. This necessitates operational refurbishment of the plant to replace these elements to ensure the plant's functionality can be maintained for its full working life. Operational refurbishment can also be required where it is found to be economic to extend the life of the asset.

The total expenditure on operational refurbishment depends on the age profile of all plant on the system for any given year and the level of loading (Powerlink's network is heavily loaded by world standards). Aged plant (in the age band from 60% to 100% of the plant's economic life) requires the highest level of refurbishment. Plant younger than 60% of working life generally does not require major refurbishment, and plant older than 100% would normally be targeted for replacement rather than refurbishment.

The State-based regulatory environment under which Powerlink has operated in recent times has put significant pressure on the ongoing reduction of opex (direct maintenance costs have reduced from 1.1% of replacement asset value in 1996/97 to 1.0% in 1999/2000 – a reduction of 1.2% per year).

The latest benchmarking highlights this impressive cost performance, but also highlights a sub-optimal tradeoff between costs and reliability, particularly in relation to substations. It is here where there is a significant requirement for refurbishment of aged plant, and the benchmarking highlights that this cannot be delayed.

This is a major driver on the refurbishment costs in the regulatory period.

Network Monitoring and Control

Prior to the commencement of the NEM in late 1998, Powerlink's role included the State system control function. That is, Powerlink was responsible for the security and operation of the power system throughout Queensland, including the operation of the Queensland Interim Market. The system control function also included monitoring and switching of the transmission network and voltage control of the network.

Post NEM, the responsibility for the overall control of the power system has passed to NEMMCO, with Powerlink retaining the role of monitoring and switching the transmission network and voltage control of the network.

In recent years, Powerlink has improved the efficiency of this activity by:

- implementing a new, state-of-the-art computer system;
- consolidating 3 regional control centres in the State into a single central centre in Virginia;
- adopting innovative multi-skilling working arrangements.

There is minimal scope for additional efficiencies in this area. Indeed, the NEM and its agencies are driving higher future costs in this activity with the demands for more information on planned network outages and pushing those outages to non-peak times (resulting in higher labour costs for direct maintenance).

Future outlook: The costs will increase each year as the network grows and becomes more complex to operate, but the rate of increase should not be as high as the growth in network assets. There is expected to be a “step increase” of about $1.4m from 2002/03 as NEMMCO terminates an agency arrangement for services and the residual services become a code obligation for Powerlink.

8.4.3 Other Costs

Insurance

One component of operating cost that contains a particularly high degree of uncertainty in relation to future trends is insurance. The National Electricity Law was changed in 1999 to significantly increase the liabilities of TNSPs. Powerlink’s insurance costs increased correspondingly at that time and have continued to rise, even with an excellent “no-claims” history and no additional imposts from the NEM. It would appear that the insurance providers are better understanding the risks of the NEM and pricing their products accordingly.

This cost is clearly not controllable by Powerlink. There is another NEM process underway at present which is considering higher liability exposures for TNSPs. This would result in further increases in insurance costs.

Because of this uncertainty and uncontrollability, this cost item has been targetted for special treatment in the forward projections and the regulatory determination.

Contracted Services

The NEC requires Powerlink to identify non-network alternatives to network augmentations and, where appropriate, to pay for those services (eg. grid support) and recoup the costs via regulated transmission charges.

A separate paper (Reference 2) has been prepared outlining the need for inclusion of this category of expenditure. Until now, there has been no allowance for such costs in Powerlink’s opex. However, it is apparent from our network planning (section 7.3.7) and the Regulatory Test that such allowances will need to be provided for future years.

8.5 Powerlink's Base Opex

Powerlink's regulated opex for the current financial year (2000/01), referred above as the base opex, was determined by the Interim Jurisdictional Regulator (ERU) and is detailed below:

Table 8.1. Base regulated opex (2000/01)

Opex Component	$M
Direct Maintenance	33.2
Network Monitoring & Control	4.2
Support & Corporate	21.1
Contracted Services	-
Total Opex	**58.5**

8.6 Demonstrated Cost-Effectiveness

International benchmarking data shows that Powerlink is the most cost-effective transmission entity in Australia/NZ and one of the most cost-effective in the world. This data has been corroborated from multiple studies and Powerlink can identify several major initiatives which have driven this result.

This latest position of leadership in cost-effectiveness is the culmination of 5 years of focused effort.

8.6.1 Historical Efficiency Gains

Over the past 5 years, Queensland has experienced a high growth in electricity demand, which, when combined with the already heavily loaded state of the transmission grid, has driven a significant transmission capital works programme. As a result, Powerlink's regulated asset base has been growing over time. While opex has increased, as expected with a growing asset base, opex has been growing at a much slower rate than assets.

The appropriate efficiency measure for a rapidly growing network is "opex as a percentage of transmission assets," and this value has been steadily declining from 2.2% of assets (replacement value) in 1996/97 to 1.7% in 1999/2000, as shown in the figure below. This represents an average improvement of 7.2% per year.

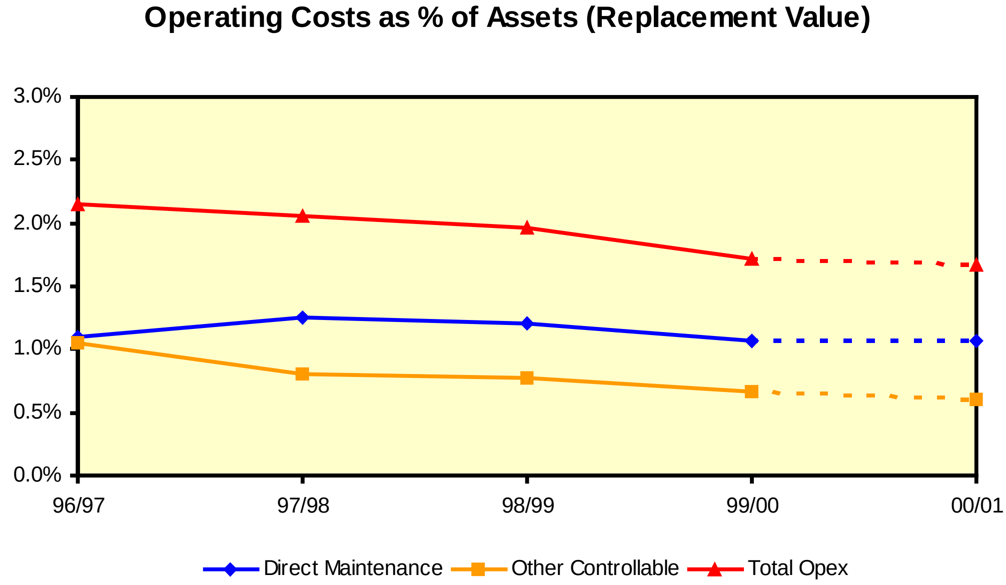


Figure 8.3. Historical trend of Powerlink's regulated opex as percentage of regulated asset base (replacement value)

Some of these cost reductions can be attributed to harnessing the economies of scale of network growth, particularly in support and corporate costs. However, such gains are not "automatic" and require the efficient deployment and operation of modern business computer systems to enable asset growth to be supported without commensurate growth in support staff. It is evident from the international benchmarking that a number of other transmission entities have been less successful in harnessing those scale economies.

Indeed, the trend line for corporate and support costs in Powerlink is almost flat in real terms even though assets have grown by almost $1 billion over 5 years. This is indicative of not only success at harnessing the economies of scale but a significant level of operational efficiency gains in the corporate and support areas over that period.

Direct maintenance costs have fallen from 1.1% of asset replacement value in 1996/97 to 1.0% in 1999/2000 – an average annual reduction of 1.2%. As there are minimal economies of scale in maintenance costs in such a geographically dispersed network, almost all of these gains have been realised through efficiency gains in maintenance strategies and maintenance work practices. Many of these resulted from initiatives undertaken as a result of ongoing participation in international benchmarking of maintenance performance.

Sources of cost savings

Powerlink has achieved a very significant reduction in controllable costs since it was corporatised in 1995. The base year (2000/01) thus incorporates the efficiencies from cost-saving initiatives over the past 5 years that have reduced operating costs to their low current levels which make Powerlink the most cost-efficient TNSP in Australia/NZ. These initiatives include:

- Changing the maintenance work practice to “starting on the job” rather than coming to a depot first. This is estimated to have improved labour productivity by between 15% and 20%.

- Consolidation to a single maintenance depot (at Virginia), which combined with the above initiative allowed all other regional depots (at Richlands, Cairns, Townsville, Mackay, Rockhampton, Gympie and Toowoomba) to be closed down.

- Consolidation of network switching centres from 3 regional centres across the State to a single central Network Switching Centre at Virginia.

- Relocation of the office facilities from a high-cost CBD location to a low-cost non-CBD location, which was previously an under-utilised Powerlink asset.

- Other changes in work practices (eg. extensive use of helicopters, single person line patrols) as a result of benchmarking studies.

- Continued extensive deployment of condition-based maintenance techniques to extend maintenance service intervals.

- The introduction of the Asset Manager / Service Provider business model provides with continual monitoring of the cost of service provision and enables the evaluation of these costs against competitive market rates. Outsourcing is adopted where it would represent a more cost-effective solution. Some 70% of network maintenance work is outsourced under a performance-based contract (Figure 8.2).

- The introduction of performance management, performance pay and gainsharing arrangements for all employees.

The benefits of these gains are already incorporated into Powerlink's present cost base. These "cards" have already been played and the results are shown by the benchmarking. There are few, if any, opportunities for further efficiency gains.

8.6.2 International Benchmarking

Comparing performance between transmission entities is not a simple matter given inherent differences in each entity's transmission task – some have very compact service territories with high load densities; others (like Powerlink) have geographically sparse territories with low load densities; some operate in very harsh climates, others in more temperate climates, etc.

In addition, there are still only a relatively small number of standalone transmission entities in the world. The vast majority of transmission entities are still part of large vertically-integrated utilities where they enjoy significant efficiencies in shared corporate and support costs. Whilst such entities can still be useful as benchmarking partners for maintenance performance, they are not useful in terms of comparing total cost performance.

Powerlink participates in international benchmarking in order to identify opportunities for performance improvement. Consequently, Powerlink only participates in those groups where considerable effort is invested in agreeing definitions, terminology and measures to ensure that the comparisons are made on an "apples vs apples" basis to the maximum extent possible.

Powerlink has participated in two such groups:

- The International Comparison of Transmission Performance (ICTP), which is coordinated by the National Grid Company (UK). The most recent study (using 1998/99 data) involved 11 standalone transmission companies from 4 continents.

- The International Transmission Operations and Maintenance Study (ITOMS), which was initiated in 1994 by a consortium of international transmission companies as a means of comparing performance and practices within the transmission industry worldwide. Powerlink has participated since 1995 with the most recent study, in 1999, involving 20 transmission companies.

Transmission utilities participate in benchmarking studies in order to identify opportunities for improvement. Because useful benchmarking is, by necessity, intrusive, companies only participate on the basis that their commercial information is kept in confidence. Without the guarantee of confidence, participation would diminish – significantly eroding the value, and statistical validity, of the exercise. In keeping with the confidentiality requirement, Powerlink is not in a position to release the reports of the studies.

However, we have endeavoured, in this Application, to present the findings of the study which are applicable while maintaining the anonymity of the other participants. In order to assure the ACCC of the authenticity of the results presented, Powerlink is willing to attest to the veracity of the results presented in this submission.

Results of the 1998/99 ICTP study

This study looks only at high level indicators of cost and service performance for standalone transmission entities. Because there is always a tradeoff between costs and service level (reliability), it is necessary to look at performance on both in order to assess *overall* performance.

Consequently, benchmarking results are often presented as a cross plot of costs against service level (reliability), with the axes located at the average level of costs and service level. This results in a presentation which shows 4 quadrants – above and below average performance on costs and service levels.

Figure 8.4 presents the results of the 1998/99 ICTP study in that format.

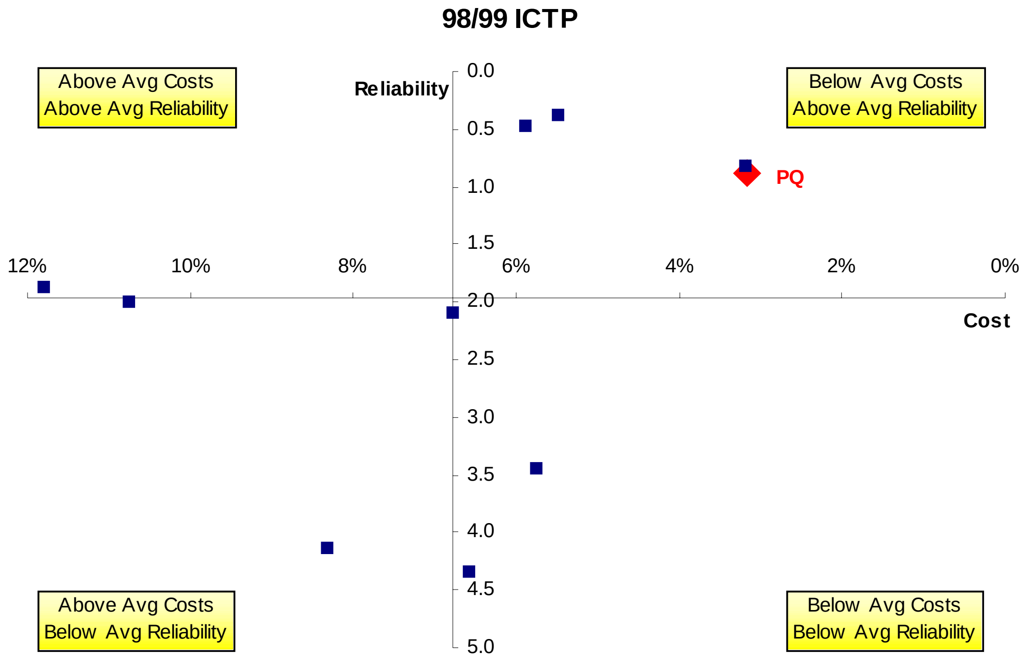


Figure 8.4. Results from the 1998/99 ICTP benchmarking study

The above results clearly indicate that Powerlink is positioned in the "best performer" quadrant, with low operating costs and high reliability. In this population, this is a "top quartile" performance.

Results of the 1999 ITOMS study

ITOMS is a much more detailed study, which is focused on maintenance performance. It measures overall maintenance performance for the two main asset categories (lines and substations) and within those categories, performance on specific maintenance activities (eg. circuit breaker maintenance).

The results for maintenance of **transmission lines** are shown in Figure 8.5 below in the usual scatter plot / quadrant format.

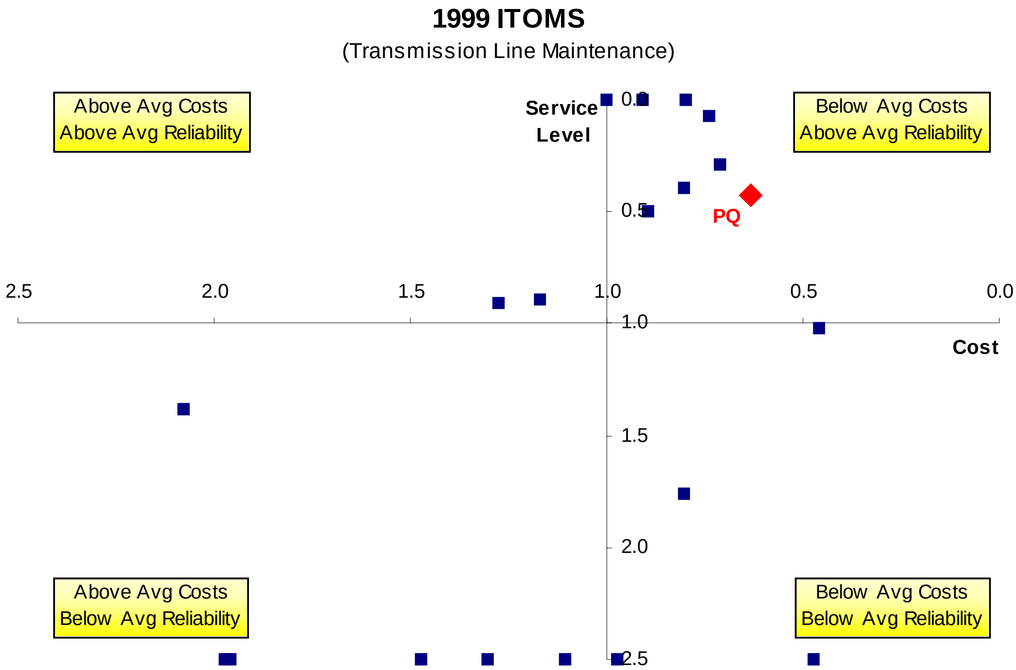


Figure 8.5. Results from the 1999 ITOMS study for transmission line maintenance

Figure 8.5 shows that Powerlink's positioning for maintenance of transmission lines is ideal.

The results for maintenance of **substations** are shown in Figure 8.6 below.

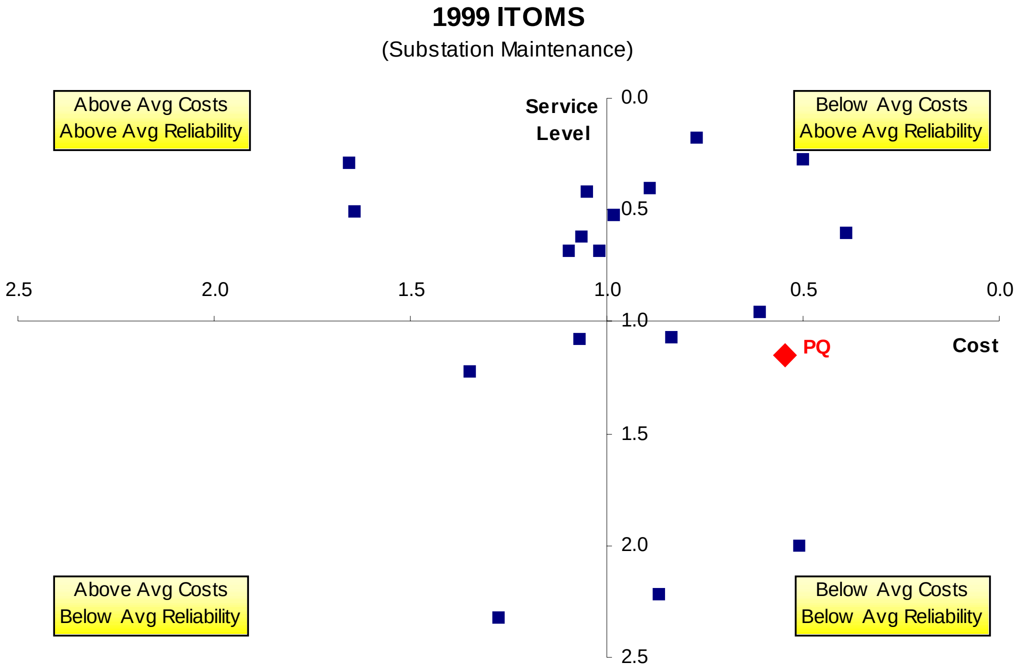


Figure 8.6. Results from the 1999 ITOMS study for substation maintenance

Figure 8.6 shows that whilst Powerlink's cost performance is outstanding, the service level is marginally below average and should be improved. This is discussed further in Section 8.7.1.

Whilst Figure 8.5 and Figure 8.6 facilitate a comparison between transmission entities of maintenance performance, they make no allowance for the inherent differences in service territory. Indeed, the Powerlink position is more commendable given its lower load density and much larger geographical territory than its peers.

Figure 8.7 shows a measure – costs per circuit kilometre – which is aimed at normalising the comparisons for the effects of geography. It illustrates that Powerlink has the lowest operating and maintenance spending per circuit kilometre of the 20 participants.

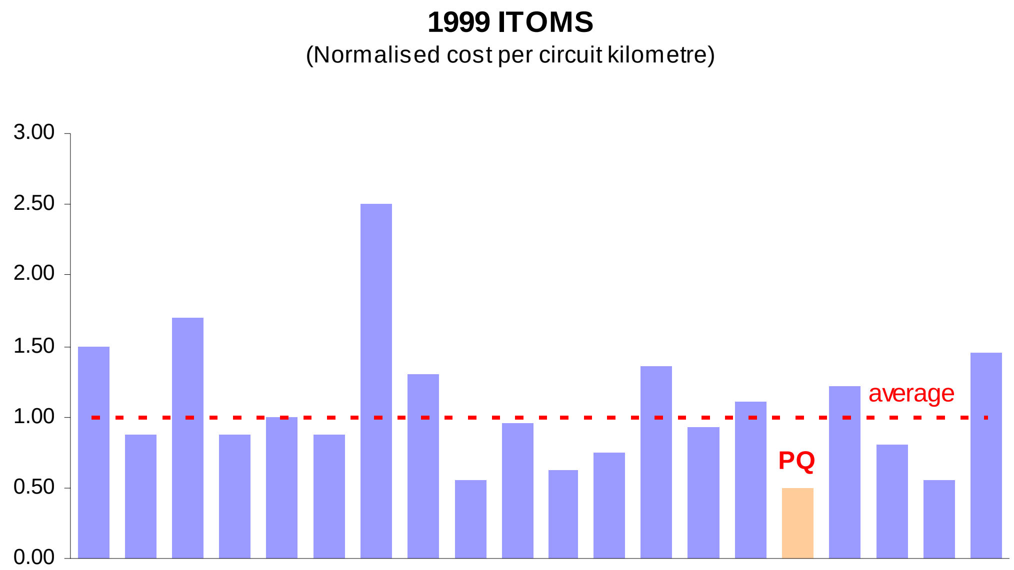


Figure 8.7. Total O&M spending per circuit kilometre

8.6.3 Regional comparisons – Australia/NZ

There are 6 standalone transmission entities in Australia, with differing network size and geographical territories. To facilitate a comparison of operating costs between entities of different size, the most appropriate measure is cost as a percentage of transmission asset value. While replacement value is the best measure for the size of the operating and maintenance task, ODRC asset values have been used in this comparison, as they are readily available from public sources.

Based on 1999/2000 data from international benchmarking and annual reports, Powerlink is the most cost-efficient with total operating costs of 2.4% of transmission assets (ODRC). For the 6 entities in the region, costs range from 2.4% to 6.2%, with an average of 4.2% (Figure 8.8).

This comparison does not take into account differences in the geography of the service territory, which disadvantages Powerlink because of the large transmission distances in Queensland.

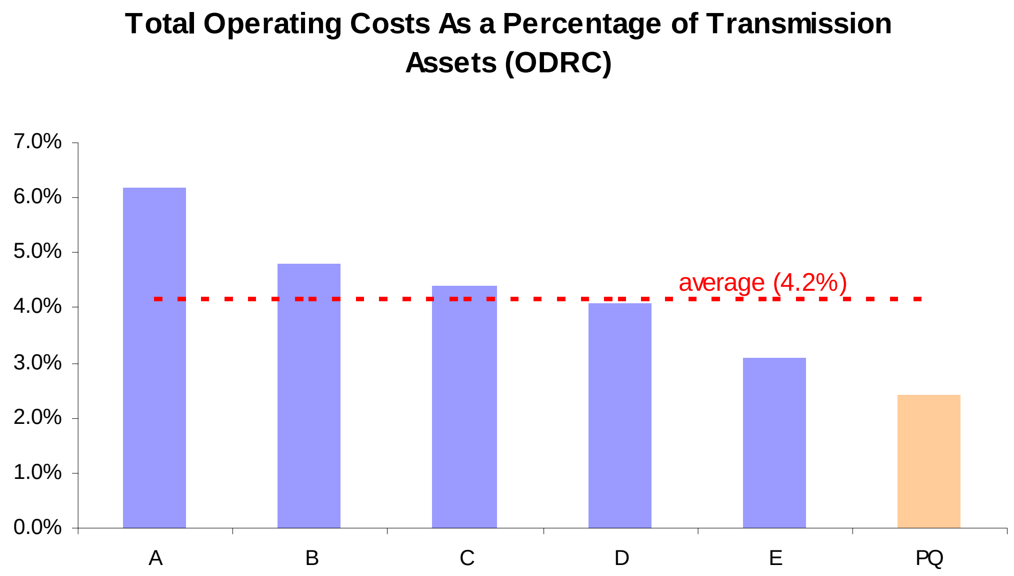


Figure 8.8. Comparison of total operating costs as a percentage of transmission assets (ODRC) for transmission entities in Australia/NZ

8.7 Opex Forward Projections

The regulated opex forecast for each year of the regulatory period is derived by considering the effect of the underlying cost drivers and any identified future efficiencies or cost burdens to the components of base opex as outlined in Section 8.4.

8.7.1 Direct operating and maintenance costs

As noted, there are minimal benefits from scale economies in this component of cost, and the efficiency gain “cards” have already been played with the benefits of those efficiencies already “locked in” the base opex.

There are, however, a number of additional cost burdens expected to arise during the coming regulatory period which have been identified and quantified:

Geographical remoteness of new assets

Most of the recent additions to Powerlink’s assets – the Queensland-New South Wales interconnector and the Calvale-Tarong line – are far away from the existing maintenance service area and service depot (Figure 8.9). Due to travel distances and costs, the costs of maintaining these lines will be proportionally higher than the average costs for the rest of the network, which make up the base opex.

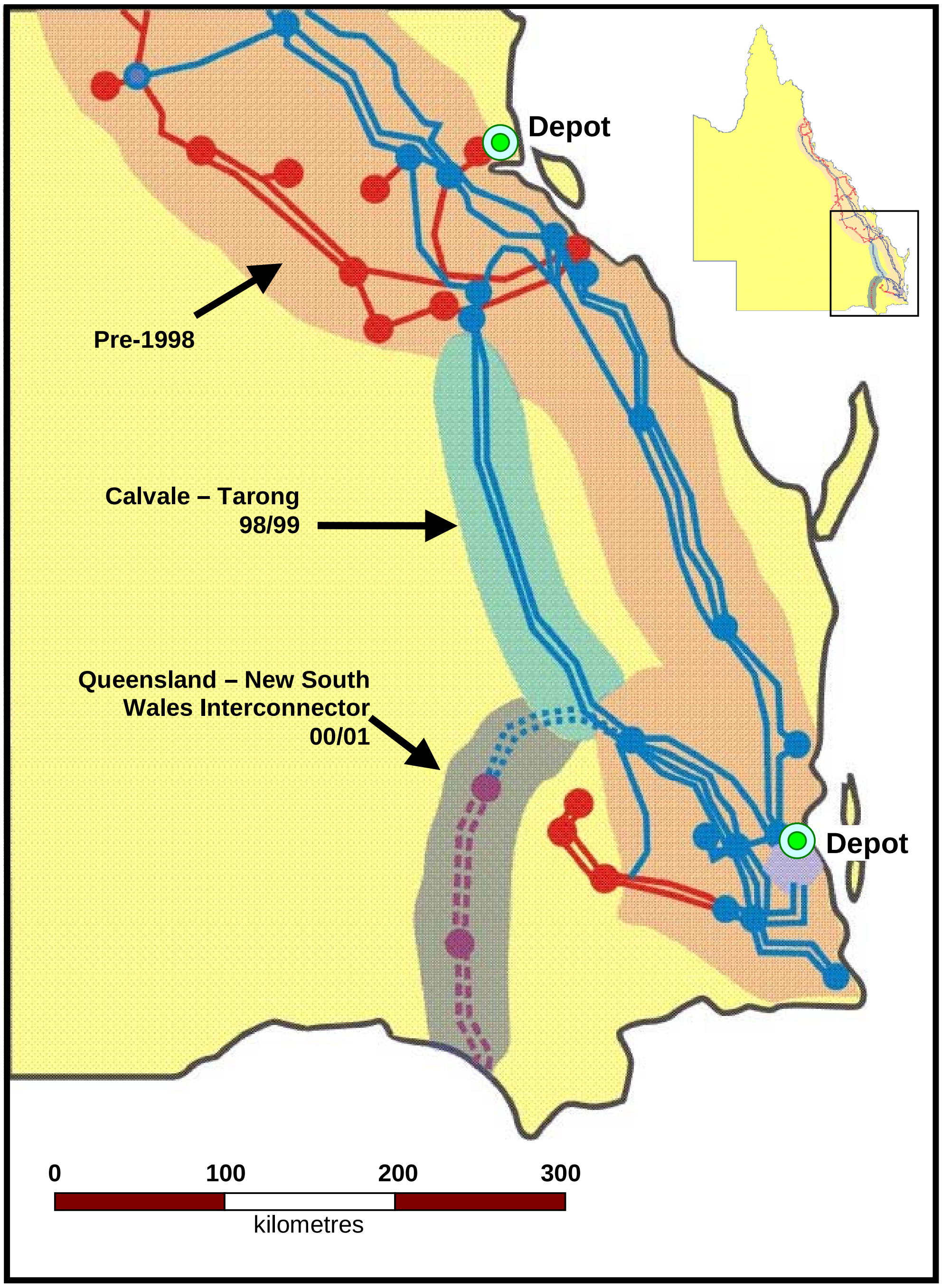


Figure 8.9. Operating in more remote locations

NEM pressure on outages

Market participants, and NEMMCO via its system security role, have encouraged Powerlink to rearrange its approach to maintenance outages so as to minimise the impact of the outage on both the market and the power system security.

This requires Powerlink to undertake higher cost activities including:

- Out-of-hours work (weekend and overnight) with higher labour costs;
- More “live” work with higher labour and equipment costs;
- Payments to generators for short-term grid support to ensure system security;
- Cancelling outages at short notice if market conditions change.

Powerlink accepts that the overall benefit to the market outweighs the additional cost impost on Powerlink and believes that the additional costs are legitimate costs for regulatory purposes.

Operational refurbishment

The ITOMS benchmarking for substations shows that Powerlink has arrived at a sub-optimal point in the tradeoff between costs and reliability. This is shown in Figure 8.10 below.

This conclusion is supported by “bottom-up” analysis of the asset management system which shows that there is an increasing amount of aging plant which needs refurbishment and the observation that a substantial amount of the most recent increases in “system minutes lost” can be attributed to aging substation plant.

Powerlink believes that it needs to spend more on operational refurbishment of aging plant with the objective of moving to a better balance of costs vs reliability as shown in Figure 8.10 and has already commenced down that path during last year and has committed to an increase in 2000/01, which is well above the regulatory opex allowance from ERU.

This effort needs to be increased in future years and the regulatory outcome needs to support that initiative. The necessary costs have been included in the opex projections.

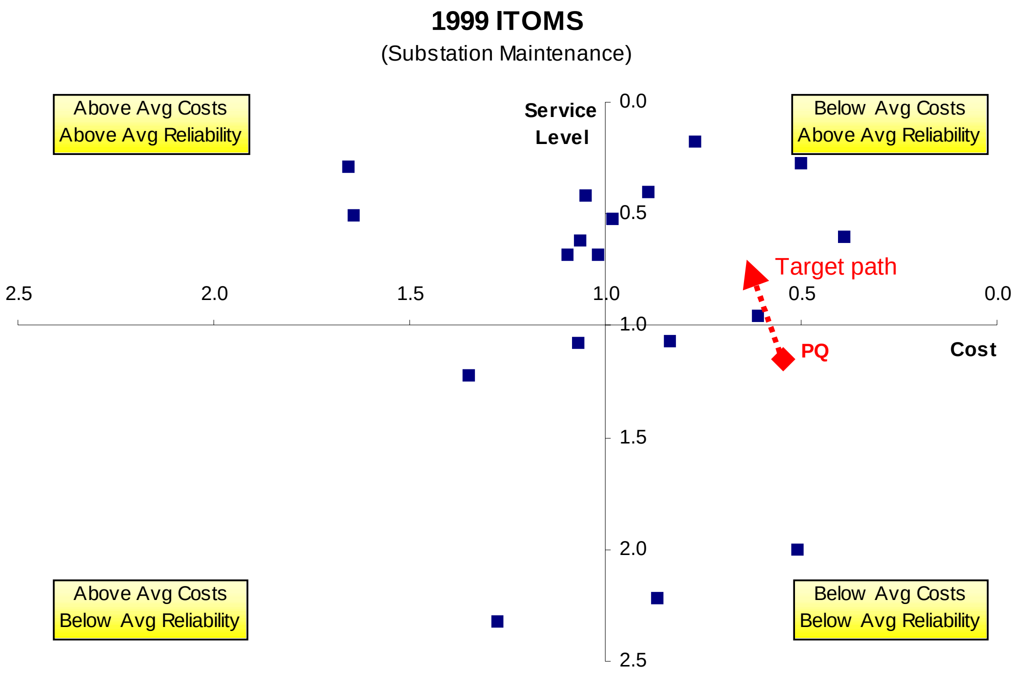


Figure 8.10. ITOMS 99 study substation cost/reliability results and target path

Network Monitoring and Control

There are some economies of scale in this activity as the network grows but not as much as for the corporate and support costs. In terms of efficiencies, Powerlink has already "played its cards" of consolidating to a single central network centre and deploying a state-of-the-art computer system to support this function.

There are a number of additional cost burdens in this area. Firstly, a number of NEC derogations, which reduced network operational standards in Queensland, lapse in early 2001. With interconnection, operation and monitoring of the network has become more complex. Powerlink has responded by establishing an asset monitoring team to meet these NEC standards and requirements.

Notwithstanding these additional cost burdens, the costs for the Network Monitoring and Control activity in 2001/02 of $4.9m compares very favourably with the $7m cost for this activity reported by TransGrid in 1999/2000 and highlights the benefits already captured by Powerlink's past efficiency initiatives.

Secondly, Powerlink's present costs include an offset of $1.4m per year received from NEMMCO for undertaking a range of power system security functions as an agent of NEMMCO. NEMMCO has indicated that it wishes to terminate that arrangement with the obligations becoming a Powerlink code obligation to be funded from regulated transmission charges. This position has been recommended to the jurisdictions by the MSORC. In practical terms, the likely timing is from July 2002 and hence this cost offset has been removed from the projections from the 2002/03 year onwards. The effect is a "step increase" in those costs.

8.7.2 Corporate and Support Costs

These costs are subject to economies of scale provided that modern business computing systems have been deployed. The opex projections reflect that by showing no increase in real terms over the regulatory period, despite a significant increase in network assets being managed. In essence, Powerlink is committed to successfully harnessing these significant economies of scale.

As a consequence, corporate and support costs associated with continuing our present obligations will decrease from 0.6% of transmission assets (replacement value) at the start of the regulatory period (2002/03) to 0.5% in the final year on the regulatory period (2006/07) – a reduction of 3% per annum.

There are no opportunities for further efficiencies as Powerlink has already "played the cards" available in this cost component:

- ❖ It has relocated its office from the high-cost CBD to a lower cost non-CBD location.
- ❖ It has deployed, in 1998/99, a fully integrated business computing system which enables significant increases in assets to be managed without corresponding increases in corporate and support costs.

There are, however, specific support areas where the NEM and the NEC are imposing additional cost burdens in the future:

- ❖ Calculation of network constraint equations – NEMMCO has recognised that there is considerable value to the market in having comprehensive constraint equations which can dynamically reflect the effects of all the influencing factors, including generation patterns, on the transfer capability of network elements. Powerlink accepts this proposition and has incorporated the associated costs in the opex projection.

- Meeting the administrative costs of the NEC process for the approval of new network augmentations. NECA has requested the ACCC to authorise code changes which impose significant additional administrative costs in relation to the documentation of new small network augmentations and in responding to enquiries from market participants in relation to these. This requires additional staffing.

- Meeting the administrative costs of regulatory reporting. The ACCC have identified two specific areas where regular reporting is required (viz. Regulatory accounts – financial, opex, capex and pass-throughs - and service standards). This represents data acquisition, reporting and auditing requirements additional to normal business and statutory reporting requirements.

The effect of these additional cost burdens has been incorporated into the opex projections.

8.7.3 Insurance

The opex projections include the costs of insurance based on present (early 2001) levels of liabilities.

Future costs are outside Powerlink's control and the present MSOIAC2 process may well result in higher levels of liabilities and insurance costs from December 2001.

Powerlink proposes that projected future costs for its *current level of liabilities* be incorporated in the allowable opex and that additional imposts be allowed on a cost pass-through basis.

8.7.4 Grid Support Costs

As discussed in section 7.3.7, non-network options, in the form of generator grid support, have been developed as part of the transmission plans in accordance with the requirements of clause 5.6.2 of the NEC. These costs need to be incorporated into the regulated revenue cap. Powerlink produced a discussion paper (Reference 2) which was presented at a public forum (November 2000) outlining the need for inclusion of this category of expenditure.

Due to the lack of history and the uncertainty associated with grid support, Powerlink proposes an annual revenue cap adjustment to cover differences between the allowance and outturn grid support costs.

Table 8.2 shows the estimates which arise from the capital forecasting of chapter 7.

Table 8.2. Grid Support Costs

($'000, Nominal)	00/01	01/02	02/03	03/04	04/05	05/06	06/07
Grid Support	**0**	**3,687**	**5,197**	**16,617**	**15,427**	**698**	**2,257**

8.7.5 Summary of Opex Forecast

Table 8.3 shows Powerlink's estimate of future regulated operating and maintenance requirements. This is shown graphically in Figure 8.11. The graph shows the opex path prior to the introduction of the efficiency initiatives outlined in Section 8.6.1 compared to our current projection, which incorporates the effect of these initiatives together with an estimate of both future efficiency gains and the additional cost burdens. Whilst the total opex is growing in nominal terms due to the growth in assets and inflation during the period, the operating costs as a % of network assets (replacement value) decreases from 1.77% at the start of the regulatory period (2002/03) to 1.72% in the final year of the regulatory period (2006/07) – a reduction of 0.7% per annum.

Table 8.3 also includes an allowance for grid support as described in Section 7.3.7. The estimates of grid support costs have been developed in conjunction with the capital forecasts (Chapter 7) to avoid 'double counting'. However, they must be expensed as an operating cost rather than capex as there is no asset being created.

Table 8.3. Regulated opex forecast

Regulated opex Forecast ($'000, Nominal)	Base Year 00/01	First Regulatory Period 01/02	02/03	03/04	04/05	05/06	06/07
Maintenance	33,236	36,487	38,979	42,032	44,528	46,942	50,399
Network Monitoring & Control	4,237	4,882	6,659	7,014	7,383	7,766	8,163
Support / Corporate	21,107	23,134	24,705	25,579	26,525	27,672	28,564
Regulated Opex (subtotal)	**58,580**	**64,503**	**70,342**	**74,626**	**78,436**	**82,380**	**87,127**
Grid Support	0	3,687	5,197	16,617	15,427	698	2,257
Total Opex	**58,580**	**68,190**	**75,540**	**91,243**	**93,863**	**83,078**	**89,384**

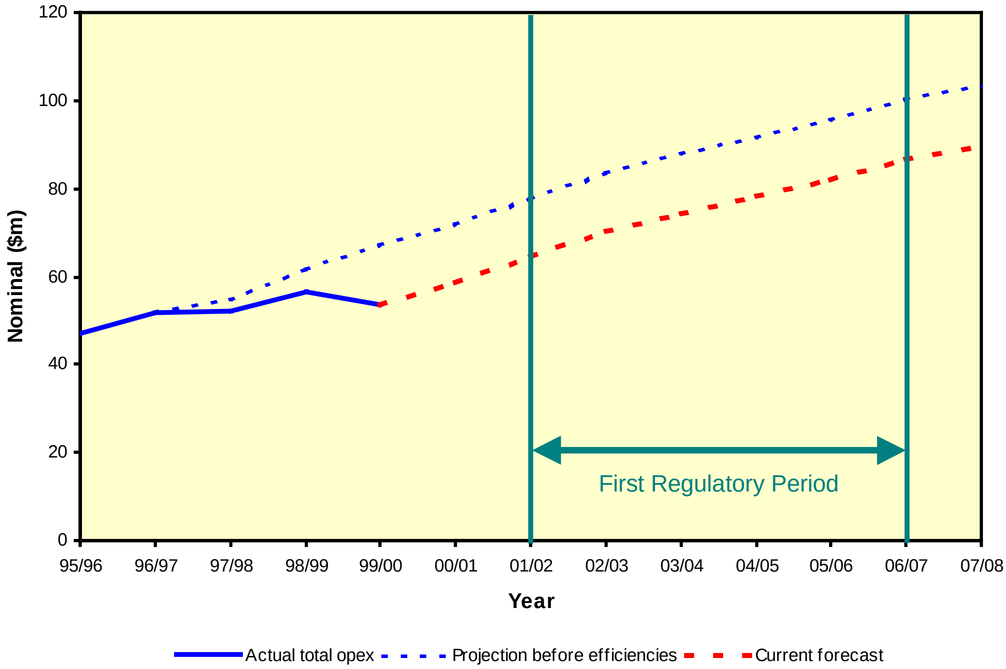


Figure 8.11. Powerlink's Opex Forecast (excluding grid support)

9 Depreciation

9.1 Introduction

This Chapter of the submission outlines the estimate of depreciation expense for Powerlink's *regulated* assets. As noted previously, the non-regulated assets are accounted for separately.

9.2 Depreciation

Australian Accounting standards characterise depreciation as the recognition of the reduction of economic benefits embodied in depreciable assets (assets of physical substance expected to be used for more than one financial period) that are consumed or lost in a financial period. Australian Accounting Standard AASB 1021 requires that "the depreciable amount of a depreciable asset shall be progressively recognised in the profit and loss and other operating statement by means of depreciation expenses".

Accounting standards recognise that a characteristic common to all physical assets held on a long-term basis, with the exception generally of land, is that their useful lives are limited because their service potential declines over time to a point where it is either consumed or lost.

This decline can occur due to factors such as wear and tear, technical obsolescence and commercial obsolescence. The possibility of obsolescence, both technical and commercial, is a factor which exists regardless of the physical use of an asset.

The useful life of an asset is usually assessed and expressed on a time basis. In determining the useful life, the following factors need to be considered:

- in the case of physical assets, the potential physical life of the asset, that is, the period of time over which the asset can be expected to last physically, at a projected average rate of usage and assuming adequate maintenance

- in all cases, the potential technical life of the asset, that is, the period of time over which the asset can be expected to remain efficient having regard to technical obsolescence

- in all cases, the expected commercial life of the asset, corresponding to the commercial life of its product or output (the possibility of an alternative use for the asset by the entity needs to be kept in mind)

- in the case of certain rights and entitlements, the legal life of the asset, that is, the period of time during which the right or entitlement exists.

Several methods are available for allocating the depreciable amount where the useful life is estimated on a time basis, according to whether it is considered that the pattern will remain constant from reporting period to reporting period, or will increase or decrease over time. The straight-line method is a means of determining systematic allocations which are constant from reporting period to reporting period. The reducing-balance method is one of several methods yielding allocations which decrease from reporting period to reporting period. Such decreasing allocations would be justified where an asset can be expected to yield more service in the earlier reporting periods than in the later.

Powerlink has adopted the straight-line method of depreciating depreciable assets as this is considered to provide the best approximation depreciable amount consistent with the pattern of exhaustion of the service potential of Powerlink's assets.

9.3 Depreciation Calculation

9.3.1 Depreciation Methods

In SAP, the Asset Accounting Module is used for managing and controlling fixed assets. It serves as a subsidiary ledger to the General Ledger, providing detailed information on transactions in the asset portfolio.

The four depreciation calculation methods employed by Powerlink are as follows:

- The straight line from useful life method of depreciation is used to calculate depreciation for accounting purposes (except in the case of non-depreciable and low value assets).

- Low value assets are fully expensed at the end of its first month of life. Portable and Attractive (Low value) assets are items that are of a low value (under $1000) and of a mobile (portable) nature e.g. a microwave, mobile phone etc. Due to their value they do not meet the asset recording thresholds and are therefore expensed when purchased rather than capitalised as an asset.

- Non-depreciable assets such as land and capital work in progress are not depreciated.

- Depreciation for taxation purposes is calculated using a combination of straight line from useful life, straight line from a stated percentage and non-depreciable methods. This results from changes to tax legislation when different rates or different methods of calculating tax depreciation are introduced.

The above principles are applied in the calculation of depreciation expense on both the existing asset base and on forecast new assets, after they are rolled into the asset base on completion of construction.

9.3.2 Special depreciation rates

To recognise changes in the pattern of the exhaustion of the asset's service potential, some assets will require changes to depreciation rates for accounting purposes, such as

- Assets identified for replacement,

- Assets identified for scrapping,

- Refurbished assets.

Some assets will also require special depreciation rates for tax purposes, such as assets that are allowed special tax deductibility, including

- building allowance,

- computer software.

Special depreciation rates can be attributed to individual assets in these instances, rather than defaulting to the depreciation rate for the asset class.

9.4 Accounting Depreciation Forecast

The accounting depreciation forecast (for Powerlink's regulated assets) for the period 2002 to 2007 used to calculate the return of capital component of Powerlink's MAR is as follows:

Table 9.1. Accounting Depreciation

2001/02 $m	2002/03 $m	2003/04 $m	2004/05 $m	2005/06 $m	2006/07 $m
99.7	106.2	111.4	119.3	126.1	133.3

In accordance with the post-tax nominal framework Powerlink has made an allowance for "economic depreciation" which is the accounting depreciation less the annual inflation effect on the asset base. The forecast "economic depreciation" is as follows:

Table 9.2. Economic Depreciation (Assuming CPI=2.5%)

2001/02 $m	2002/03 $m	2003/04 $m	2004/05 $m	2005/06 $m	2006/07 $m
40.7	44.5	46.4	50.9	53.4	56.9

9.5 Taxation Depreciation

The taxation depreciation forecast (for Powerlink's regulated assets) for the period 2002 to 2007 is as follows:

Table 9.3. Taxation Depreciation

2001/02 $m	2002/03 $m	2003/04 $m	2004/05 $m	2005/06 $m	2006/07 $m
97.2	101.7	104.8	110.6	115.1	120.2

It should be noted that Powerlink Queensland entered into a Cross-border lease of its regulated network assets in December 2000. The effect of the Cross-border lease is to increase the tax asset base from the current accounting book value of the assets, as at the date of the transaction, for taxation depreciation purposes.

9.6 Summary

Powerlink has adopted the “straight-line from useful life” method to calculate depreciation for accounting purposes (except in the case of non-depreciable and low value assets). This is considered to provide the best approximation of depreciation consistent with the pattern of exhaustion of the service potential of Powerlink’s assets for regulatory purposes.

Some assets will require changes to depreciation rates for accounting purposes to recognise changes in the pattern of exhaustion of the asset’s service potential. Depreciation rates can be attributed to individual assets in these instances.

The depreciation forecast from the 1 July 2001 opening asset value and for each year of the regulatory period is summarised below:

Table 9.4. Depreciation Forecast for Regulated Assets

Depreciation	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Straight Line Depreciation	99.7	106.2	111.4	119.3	126.1	133.3
Economic Depreciation	40.7	44.5	46.4	50.9	53.4	56.9
Taxation Depreciation	97.2	101.7	104.8	110.6	115.1	120.2

10 Total Revenue

10.1 Introduction

Powerlink's application for revenue is based on a post-tax nominal accrual building block approach.

The revised building block formula becomes:

MAR = return on capital + return of capital + opex + tax + capex adj

+ contracted services adj + insurance adj

= (WACC * ODRC) + D + opex + tax + capex adj + contracted serv adj

+ insurance adj

where:

WACC	=	post-tax nominal weighted average cost of capital ("vanilla" WACC);
ODRC	=	optimised depreciated replacement cost;
D	=	depreciation;
opex	=	operating and maintenance expenditure;
tax	=	expected regulated business income tax payable;
capex adj	=	MAR adjustment for actual capex;
contracted serv adj	=	MAR adjustment for actual contracted services expended;
insurance adj	=	MAR adjustment for additional insurance costs

10.2 Assessment of Building Block Components

10.2.1 Asset Base

Powerlink has modelled its regulated asset base over the regulatory period. The 1 July 2001 opening asset value of **$ 2,470.3 M** was established in Chapter 6.

Asset values are rolled forward by taking the closing asset value and using it as the opening value for the next year, converting it to a nominal figure by adding an inflation adjustment, adding in any capital expenditure and subtracting disposals and depreciation for that year.

Capex

A forecast of capital expenditure is detailed in Chapter 7. Because the accrual building block method adopted in this Application calculates return on assets using the opening asset balance, an additional financing cost is applied to the new capex to take account of its progressive capitalisation throughout the previous year. This approach is adopted as an alternative to calculating return on the average of opening and closing balance, an approach used by other regulators.

A summary roll-in of completed capital, including financing costs, is given below.

Table 10.1. Summary of Capex Roll-in

	2001/02 $m	2002/03 $m	2003/04 $m	2004/05 $m	2005/06 $m	2006/07 $m
Capex Roll-in (incl FDC)	148.6	171.5	180.0	221.2	192.1	88.6
Additional FDC	6.6	7.8	8.2	10.1	8.8	3.6
Total Capex Roll-in	155.2	179.3	188.2	231.3	200.9	92.2

Inflation

An inflation rate of **2.5%** per annum has been adopted for each year of the regulatory period.

Depreciation

Accounting depreciation for the regulated asset base has been derived and detailed in Chapter 9 of this Application. Accounting depreciation commencing from the 1 July 2001 opening asset value and for each year of the regulatory period is summarised below.

Table 10.2. Summary of Accounting Depreciation

2001/02 $m	2002/03 $m	2003/04 $m	2004/05 $m	2005/06 $m	2006/07 $m
99.7	106.2	111.4	119.3	126.1	133.3

The ACCC has used an “economic depreciation” approach in previous revenue decisions. The “economic depreciation” incorporates both the straight line depreciation and inflation component to provide a consistent approach when a nominal return framework. “Economic depreciation” has been derived and is summarised below.

Table 10.3. Summary of “Economic Depreciation”

2001/02 $m	2002/03 $m	2003/04 $m	2004/05 $m	2005/06 $m	2006/07 $m
40.7	44.5	46.4	50.9	53.4	56.9

10.2.2 Opex

Chapter 8 of this Application details Powerlink’s requirement for operating and maintenance expenses for each year of the regulatory period. This opex requirement, in nominal price levels, is summarised below.

Table 10.4. Summary of Operating and Maintenance Expenses

2001/02 $m	2002/03 $m	2003/04 $m	2004/05 $m	2005/06 $m	2006/07 $m
68.2	75.5	91.2	93.9	83.1	89.4

10.2.3 Income Tax Payable

Tax depreciation associated with the regulated asset base is outlined in Chapter 9. Based on this tax depreciation and the revenue requirement and operating costs (including interest costs) proposed in this Application, tax payable has been determined. Estimated tax payable is summarised below.

Table 10.5. Summary of Income Tax Payable

2001/02 $m	2002/03 $m	2003/04 $m	2004/05 $m	2005/06 $m	2006/07 $m
29.4	31.4	33.7	36.1	39.0	41.4

10.2.4 Weighted Average Cost of Capital

Powerlink proposes that a post-tax nominal WACC of 7.91% should apply to the accrual return model. This value equates to a post-tax nominal return on equity of approximately 13.97% which is considered consistent with recent regulatory decisions, taking into account market variations with the “risk free” bond rate.

Derivation of this WACC value is detailed in Chapter 4 of the Application.

A post-tax nominal accrual building block model which explicitly allows for income tax requires that a return based on vanilla WACC is adopted. Consistent with the derivation of the above post-tax nominal WACC of 7.91% and post-tax nominal return on equity of 13.97%, a post-tax nominal vanilla **WACC of 10.19%** has been derived.

10.2.5 Imputation Credits

Gamma represents the proportion of franking credits which can, on average, be used by shareholders of the company to offset tax payable on other income. Powerlink proposes a value of gamma of 45%. Details of this proposal are outlined in Chapter 4.

10.3 Asset Base Roll Forward

Asset roll forward commencing 1 July 2001 is outlined below:

Table 10.6. Summary of Regulated Asset Base Roll Forward

	2001/02 $m	2002/03 $m	2003/04 $m	2004/05 $m	2005/06 $m	2006/07 $m
Opening Asset Value	2,470.3	2,584.8	2,719.7	2,861.5	3,041.9	3,189.5
Economic Depn.	(40.7)	(44.5)	(46.4)	(50.9)	(53.4)	(56.9)
Capital additions	155.2	179.3	188.2	231.3	200.9	92.2
Closing Asset Base	2,584.8	2,719.7	2,861.5	3,041.9	3,189.5	3,224.8

10.4 Return on Capital

Return on capital has been calculated below by applying a post-tax nominal vanilla WACC to the opening regulated asset base.

Powerlink has based the return on capital on opening asset values in line with previous ACCC determinations. In the past regulators have taken either of two approaches. The first is to calculate the return on capital using an average of opening and closing asset values. The second is to use the opening asset values as the basis for the return. However as this second method does not provide a return on assets capitalised during that year until the following year, we believe it is appropriate to apply a finance during construction allowance for a six month period for that year.

Table 10.7. Summary of Return on Capital

	2001/02 $m	2002/03 $m	2003/04 $m	2004/05 $m	2005/06 $m	2006/07 $m
Opening Asset Value	2,470.3	2,584.8	2,719.7	2,861.5	3,041.9	3,189.5
Return on Capital	251.8	263.5	277.2	291.7	310.1	325.1

10.5 Total Revenue

Based on the revenue parameters outlined in this Chapter of the Application and applying the building block approach, the following unsmoothed revenue requirements have been determined.

Table 10.8. Summary of Regulated Revenue Calculation

	2001/02 $m	2002/03 $m	2003/04 $m	2004/05 $m	2005/06 $m	2006/07 $m
Return on Capital	251.8	263.5	277.2	291.7	310.1	325.1
Return of Capital	40.7	44.5	46.4	50.9	53.4	56.9
Operating expenses	68.2	75.5	91.2	93.9	83.1	89.4
Taxes Payable	29.4	31.4	33.7	36.1	39.0	41.4
Less Franking Credits	-13.2	-14.1	-15.2	-16.2	-17.5	-18.6
Unadjusted Revenue	**376.9**	**400.8**	**433.4**	**456.3**	**468.0**	**494.2**

10.6 Revenue Cap Adjustments

10.6.1 Adjustment for Actual CPI

The derivation of revenue caps has been based on a CPI annual movement of 2.5% over the regulatory period. Because the impacts of variations in actual CPI compared with the pre-estimated value compounds over time, it is proposed that an automatic adjustment be allowed to take account of actual (historic) CPI. The actual revenue caps to apply will be based on real revenue caps (in 2001/02 price levels) adjusted for the historic movement in CPI.

10.6.2 Adjustment for Actual Capex

The proposed capex adjustment formula is outlined in Section 7.3.9 of the Application and summarised below.

1. adjustment is based on the difference between the actual (including efficiency adjustments) and forecast capex roll-in (adjusted for FDC);

2. the adjustment be based on the cumulative capex difference multiplied by (WACC + economic depreciation);

3. an adjustment only be made if the cumulative difference between actual and estimated capex exceeds 5% of the estimated quantity.

10.6.3 Adjustment for Contracted Services

As outlined in Chapter 8 of the Application, an annual revenue cap adjustment is proposed to cover actual expenditure associated with regulated contracted services for grid support requirements. The adjustment will be made to each year revenue cap based on the difference between actual expenditure, including reasonable administrative and overhead costs, and the allowance provided for in the opex budget. This Application includes the following allowance, including associated costs.

Table 10.9. Summary of Included Grid Support Costs

	2001/02 $m	2002/03 $m	2003/04 $m	2004/05 $m	2005/06 $m	2006/07 $m
Contracted Services	3.7	5.2	16.6	15.4	0.7	2.3

10.6.4 Adjustment for Insurance

In line with Section 8.7.3 of this application Powerlink proposes that any additional imposts over the projected level of insurance costs be allowed on a cost pass-through basis.

10.7 Summary of Required Revenue Caps

The annual nominal revenue caps required by Powerlink to support its ongoing business activities have been calculated using the post-tax nominal accrual building block approach. The regulated revenue caps are:

Table 10.10. Calculated Revenue Cap

	2001/02 $m	2002/03 $m	2003/04 $m	2004/05 $m	2005/06 $m	2006/07 $m
Regulated Revenue	**376.9**	**400.8**	**433.4**	**456.3**	**468.0**	**494.2**

As outlined in this Application, the above revenue caps will be subject to annual formulised adjustments based on the previous year historical outcomes in relation to:

- Actual CPI relative to the estimated CPI;
- Actual capital roll-in compared with the allowance in the revenue model; and
- Actual expenditure on contracted grid support services and insurance compared with the allowance in the revenue model.

11 Service Standards

11.1 Introduction

The ACCC has stated in its DRP that as part of the application review process, it will establish for the TNSP a set of service standards and associated monitoring program. In addition, the ACCC will publish annual statistics comparing the performance of the TNSPs it regulates.

It is Powerlink's view that traditional annual supply quality statistics are not a sound basis for service standards targets. Supply quality statistics are important to customers as they are a measure of the quality of the product they receive. However, because the traditional measures are not all related to events under the TNSP's control, nor are they presented in a form that is statistically sound in terms of measuring performance, they are not recommended as the prime measure of service standards for the regulatory compact between the ACCC and the TNSP.

Furthermore, it is pointed out that there are additional issues which impact on service delivery and need to be incorporated in the package of measurements.

In summary, this section seeks to:

- Reinforce that service standard measures need to be related to events directly under the control of the TNSP;
- Demonstrate that traditional annual supply quality statistics, while useful, are not, on their own, an appropriate measure for service standards;
- Concludes that service standard measures need to be linked to customer satisfaction measures and "impact on market" measures as well as the traditional quality of supply (reliability) measures.

The paper also suggests a way of moving forward on this issue as follows:

- Compile annual supply quality statistics based on the list in Annex 8.1 of the DRP. In publishing these statistics, it needs to be acknowledged that these measures have extremely limited value as TNSP performance measures;

- Utilise Powerlink’s present service standard measures as a means of monitoring and setting future performance targets;

- As part of the finalisation of the DRP, develop a consistent and meaningful set of measures which allow network reliability, customer satisfaction and market impact to be monitored.

11.2 Philosophical Approach

As a general philosophy, Powerlink believes that:

- Standards must reflect the fundamental accountability principle that one should be held accountable for things which are within one’s control, and conversely, one cannot be held accountable for things which are outside one’s control.

- Standards for network performance must be consistent with the standards set for planning and developing the network. Specifically, a TNSP cannot be accountable for achieving a standard which exceeds the criteria set down in the National Electricity Code for the planning and development of the network (especially Schedule 5.1).

- Standards for network performance must be consistent with the standards and criteria set for operation of the network. Specifically, a TNSP cannot be accountable for achieving a standard which exceeds the criteria used by NEMMCO to operate the power system (eg the operational security criteria in Chapter 4 of the NEC).

- Standards for network performance must be consistent with the Capex and Opex allowed by the economic regulator. For example, a TNSP cannot deliver higher standards during peak transfer periods if the allowed Opex does not cover the additional costs of moving network maintenance activities to off-peak periods.

- Standards for network performance cannot be “one size fits all”. The standards need to reflect both the different requirements of users connected to the network and the different environmental constraints (in Qld, this includes vast distances and hence delays in getting to assets to repair problems), climatic events (cyclones and thunderstorms) and difficult terrain (eg World Heritage rainforests with only helicopter access). Whilst one would expect these differences to be accommodated in the network planning standards in the NEC, this is not presently the case. This is acknowledged in the DRP in Section 8.2 Commission Considerations (Page 99) *"The Commission acknowledges that TNSPs may not be directly comparable as each TNSP may be operating under different circumstances."*

11.2.1 Factors influencing Network Standards

Controllability by the TNSP

A TNSP can, within the constraints imposed by the allowed Capex and Opex, determine and apply asset management strategies (replace, refurbish, repair), maintenance strategies, and maintenance and operational practices which can have a significant influence on the resultant network performance.

However, there are also many factors outside the control of the TNSP which can impact the resultant network performance:

- weather/natural events – cyclones, storms etc. In recent years, many of the larger losses of supply in Queensland due to the transmission network have been attributable to such events. A localised mini-tornado destroyed 5 transmission towers in the Brisbane Valley; an uncontrolled bushfire caused the 2 transmission lines supplying a large part of South East Queensland to disconnect.
- NEMMCO intervention – NEMMCO can, for system security reasons, deny outages of plant for necessary maintenance work and this may ultimately result in unplanned outages of that plant. The initiating security threat may have arisen due to other external factors eg sudden outage of generating capacity;
- Historic Network – the network is made up of assets which have been installed over the past fifty years. The network will have an underlying performance characteristic which is determined by the network itself (its topology and design) which is a cumulative result of fifty years of investment. Short term capital or operating investment will have little impact on this underlying characteristic and only after many years of concerted investment will any significant impact be made;

- Other participants – while TNSPs have firm obligations relating to maintaining network integrity, other participants who significantly impact on network availability (eg generator or MNSP dispatch and customer power factor) are able to take decisions without regard to network security.

Figure 11.1 illustrates the concept that supply quality output measurements capture the impacts from a wide range of causes. Linking a supply quality output to a single input such as operating performance is inaccurate and inappropriate. The challenge is to identify output measures which are directly linked to operating performance.

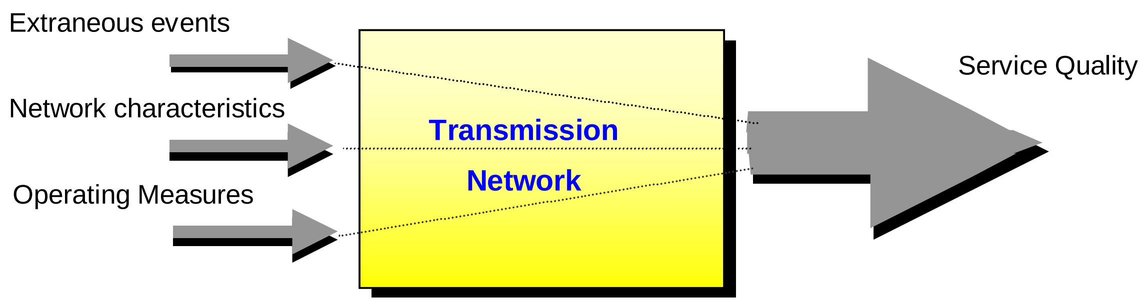


Figure 11.1. Transmission Service Quality Causes

Planning Standards

The standards to which TNSPs must plan and develop their networks are outlined in Schedule 5.1 of the NEC. It has been recognised by NECA that this section of the NEC is open to multiple interpretations, including one which represents the so-called N-1 criterion. The Reliability Panel has recently initiated a review of Schedule 5.1 with the objective of clarifying the standards, and adopting an economic approach to those standards. This is likely to lead to a (welcome) move away from the economically inefficient "one size fits all" criterion implicit in Schedule 5.1.

Powerlink believes that the fact that the Reliability Panel is conducting this fundamental review makes it very difficult for the ACCC to set rigid network standards which are to apply to the next 5 years.

Operating / Security standards

NEMMCO, as the power system operator, is responsible for power system security, and in performing its role, applies criteria which it interprets from Chapter 4 of the NEC.

A detailed review of the allocation of system operating responsibilities between NEMMCO and the TNSPs (the MSORC review on behalf of the jurisdictions) has identified that there are fundamental inconsistencies between the security/operating criteria in Chapter 4 of the NEC, and the planning standards in Chapter 5. In essence, the criteria which NEMMCO can apply under Chapter 4 are higher than the planning standards.

MSORC is recommending, inter alia:

- that the standards be made consistent;
- that standards be set by an independent entity (eg Reliability Panel) using a cost/benefits analysis approach.

Again, Powerlink believes it is very difficult for the ACCC to set performance standards for the next 5 years whilst these fundamental criteria are under active review.

Allowed Capex / Opex

Whilst the connection between allowed Capex and Opex and subsequent network performance is intuitive, there are some interesting observations which support the need for a consistent approach.

Firstly, Powerlink participates in international benchmarking of its network maintenance activities. The outcomes from the benchmarking clearly show the tradeoffs implicit between costs and reliability, even amongst the better performers.

Powerlink (and 4 others) have network performance which fits into the top performing quadrant (“Above average reliability/Below average cost”). However, these top performers are at different points within that quadrant. The entity with the highest reliability has costs which are well above the lowest cost performer; the entity with the lowest costs has reliability which is well below the entity with the highest reliability (Powerlink is in the middle of these extremes). It is clear that these various entities have made tradeoffs between costs and reliabilities, and that it is inappropriate to set the reliability standards without ensuring there are allowed costs which are consistent with those standards. Powerlink could, for example, move to the position of the highest reliability entity (by increasing costs) or the position of the lowest cost entity (by reducing reliability).

On another matter, Powerlink is also aware of suggestions that TNSPs be encouraged / incentivised to deliver network performance outcomes which are more aligned with the needs of the market. Specifically, that network outages be undertaken “out of peak” transfer times. The rationale is that the market costs of network outages in peak times can be significant – that is, there is significant market benefit in having network maintenance done either “off peak” or done as “live work”.

This suggests that the network performance standards might also need to be time-based (eg with higher standards of circuit availability during peak transfer times, and lower standards off-peak).

Assuming that the claimed market benefits exist, Powerlink supports this approach PROVIDED that the ACCC, as Regulator, will allow Powerlink the higher opex to undertake live work (higher labour and equipment costs) and undertake more maintenance on weekends (higher labour costs).

11.3 Monitoring Reliability

Powerlink has performed a great deal of research to arrive at a set of meaningful indicators of changes to system reliability. Methods have been developed using rigorous mathematical techniques to remove as far as possible any subjectivity. An overview of this research has been presented in conferences and is given in References 3, 4 and 5.

Monitoring reliability poses the same problems as that of monitoring climate change. The fact that a large flood occurs does not necessarily mean that the climate is changing, it merely means that large floods occur occasionally. What is important is not so much how big the flood was, but how often it occurs. If a flood over a given size used to occur as a 1 in 100 year event, but now happens every 50 years, then something has changed.

System reliability can be analysed using exactly the same methods that are used to analyse flooding and climate change.

11.3.1 The Problem With Traditional Reliability Measures

The most commonly used measure of system reliability is a statistical measure termed System Minutes (SM); which is in effect a composite measure of both the time (duration of outage) and severity (extent of unsupplied/lost energy). System Minutes is defined as:

SM = (Demand Unsupplied x loss of supply duration) ÷ (Maximum system demand)

Figure 11.2 gives a graphical representation of system minutes on the Powerlink transmission network in recent years.

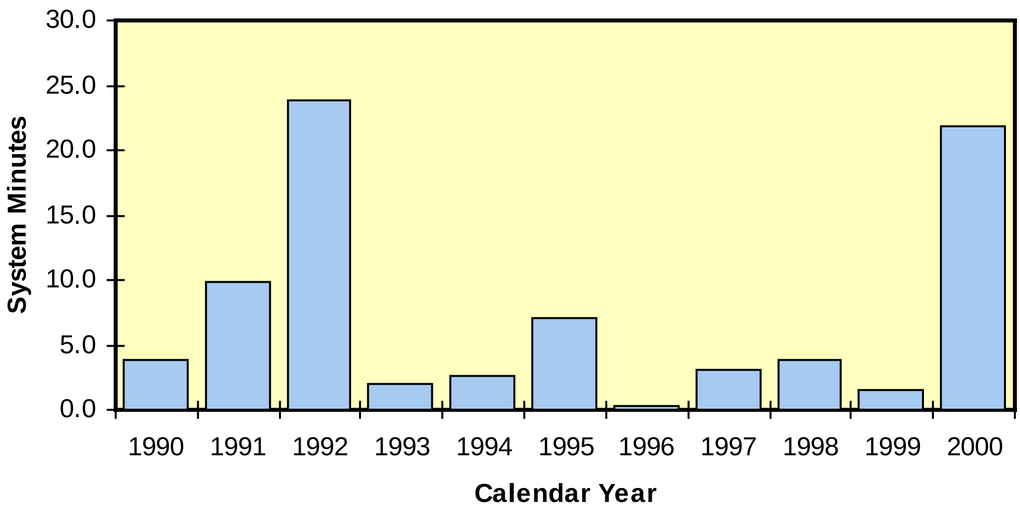


Figure 11.2. System minutes for loss of supply caused by events on Powerlink's transmission grid

While the above plot is a historic record of transmission interruptions, it is quite meaningless as a performance measure. The data fits within the probability distribution of Figure 11.3.

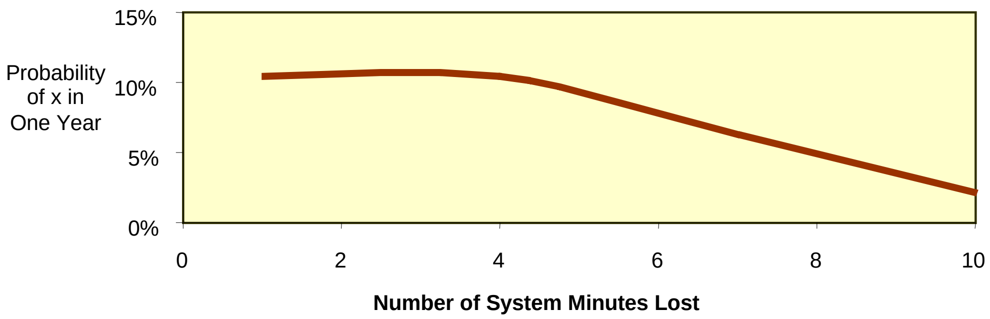


Figure 11.3. Probability profile for annual system minutes lost

From this plot, it can be seen that the mode (ie the typical score) will be around 2 to 4 system minutes lost. However, because of the long tail at the right, the long term average will be much higher, and in fact it can be shown that it tends to infinity. Detailed analysis shows that a single event of 9 system minutes or greater is a 1 in 6 year event. Consequently, every 6 years on average, a target of 9 system minutes will be exceeded. Therefore, setting an *annual* target for system minutes lost, like setting a maximum flood level not be exceeded, is meaningless.

However, like floods, it is the number of large events, not the size of events themselves, that is important. It can be shown mathematically that reliability can be effectively monitored by monitoring both the total number of events per quarter greater than 0.2 system minutes, and the total number of events per quarter greater than 1.0 system minutes. The 0.2 and 1.0 system minutes have been chosen because two points are needed to fully define the reliability characteristic. These points have been selected such that a reasonable quantity of data will be available on a quarterly basis.

11.4 Development of Network Service Standards

Powerlink accepts that customers are very interested in quality of supply and therefore quality statistics are needed both at the network level and connection point level. Because of the limitations of these statistics as TNSP performance measures, we suggest that when adopting these statistics, rolling averages or other statistical variants which deal with the stochastic and long term nature of the measures be employed. For example, an event which has a probability of 0.1 per annum will never manifest itself 0.1 times each year; either it will happen (1.0) or it will not occur (0).

As already pointed out, supply quality measures alone are not an appropriate control measure for operating performance of a TNSP. Supply quality measures are influenced by non-controllable events (eg weather, NEMMCO, history of network) more than by operating practices. Performance (or incentive) based measures will need to focus on outputs which are linked to controllable inputs.

Powerlink believes that any service measures should therefore encompass:

- Customer consultation and feedback;
- Impact on market participants; and
- Quality of supply (reliability).

While the relative weightings of the categories is unknown, each of these measures should factor prominently in determining the service standards being followed by a TNSP.

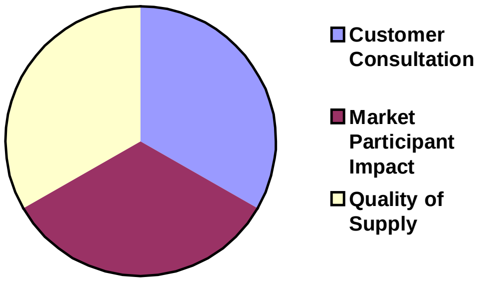


Figure 11.4. Comprehensive performance measurement components

To that effect, Powerlink agrees with the ACCC in broad terms as outlined in the draft Statement of Regulatory Principles.

- *"Service standards should balance good industry practice against customer expectations"* [Section 8.1 – Service Standards - Introduction]. Powerlink believes this is best achieved by a set of service standard measures that include a process to obtain feedback from customers, via customer surveys, on their expectations relating to the quality of service and the relationship with the service provider. This feedback is quite separate to quantitative measures applied to electrical parameters measured at the point of supply to the customer.

- *"The Commission believes that the development of market-based standards may provide a useful addition to the suite of service standards user to monitor the performance of a TNSP"* [Section 8.2 – Commission considerations]. Powerlink believes the role a TNSP plays in the minimisation of impacts of transmission network events (both planned and forced) on market participants by undertaking transmission network reconfigurations should be included in the service charter. A TNSP's business processes should be demonstrably aligned to providing direct benefits to the market on the rescheduling of planned outages where such outages have a potential detrimental impact on a market participant(s), management of transmission network constraints and speed of restoration after forced outages. This needs to be recognised in the service standards.

- *"Further, given that certain service standards already exist, either explicitly or implicitly, the Commission does not consider it appropriate for it to solely determine the service standards that must apply to TNSPs, either individually or collectively"* [Section 8.2 – Commission considerations]. Powerlink has for several years collected network performance data as part of it's own ongoing business process analysis. To minimise the cost of establishing a service standard regime, it is expected that the ACCC will acknowledge Powerlink's existing service measures, and their appropriateness to its role.

11.5 Powerlink's Present measures

11.5.1 Reliability Related Measures

Statistically sound measures have been developed within Powerlink to allow the effectiveness of "controllable" operation and maintenance practices to be assessed on a regular basis. These measures are used as part of the decision making process and include:

- Total number of events (loss of supply) greater than 0.2 sys min

- Total number events (loss of supply) greater than 1.0 sys min.

Both of the above are plotted with a 10 year history as Poisson based control chart with control limits regularly reviewed.

In addition, Powerlink uses the following frequency based measures:

- Static Var Compensator events;
- Equipment events per 1,000 circuit breakers;
- Secondary system events per 1,000 circuit breakers;
- Incident (human error) events per 1,000 circuit breakers;
- Total internal events per 1,000 circuit breakers (sum of above);
- Total external events per 1,000 circuit kms;
- Ratio of loss of supply external events to total external events;
- Ratio of loss of supply internal events to total internal events.

These measures are plotted with a 3 year history as Poisson based control charts with control limits updated annually.

Because there is a history of the above measures as performance management tools within Powerlink and, as these measures are considered to be more mathematically robust than the traditional system minute type measures, it is recommended that the ACCC adopt these measures as part of the service standard monitoring arrangement under the regulatory compact with Powerlink.

11.5.2 Customer Feedback Measures

Powerlink's management team has embarked on a program of regularly visiting each network customer (DNSP, generator and direct connect load). The aim of the program was to visit major generators and major distributors twice per year, and all other customers at least once per year. The program has been in place for the last two years with about 25 visits taking place each year.

In order to gain the most benefit from the program, visits are aimed at the executive level. In addition, Powerlink has appointed senior level customer account managers to follow through with issues raised at discussions.

In order to adapt this internal customer service monitoring program into a monitoring tool suitable for regulatory overview, it is suggested that the following measures be adopted:

- Frequency of customer visits;
- List significant issues raised (this is already done for Powerlink's internal management process);
- Steps taken to deal with issues.
- Perform Annual Customer Satisfaction Survey

A further customer service initiative which has been put in place by Powerlink involves direct interaction with customers affected by loss of supply events. Under this program, the customer account manager will contact the customer within one working day of the event to outline the underlying cause of the event and, where applicable, to identify steps being taken by Powerlink to reduce the likelihood of a recurrence.

It is therefore proposed that a regulatory performance measure would include a record of timely notification of interruption advice to customers.

11.5.3 Market Impact Measures

Powerlink does not have access to data aimed directly at monitoring the impact it may have on the market (other than the reliability/loss of supply measures). This is an area would require data from NEMMCO, particularly in relation to the impact of network constraints. It is important, however, that any future measures be carefully determined so as to measure a "controllable" measure rather than just a statistic.

11.6 Powerlink's Proposal

In order to move forward on this issue, Powerlink proposes the following three-step approach:

Step 1 Compile ongoing supply quality statistics relating to the total network and individual connection points. This will be provided on an annual basis and will align generally with the proposed data set as shown in Annex 8.1 of the DRP. In publishing these statistics, it needs to be acknowledged that these measures have extremely limited value as TNSP performance measures;

Step 2 Adopt, as part of the regulatory compact, the set of performance measures Powerlink currently uses for its monitoring processes and decision making, as outlined in Sections 11.5.1 and 11.5.2. The targets proposed for these measures are summarised in Table 11.1 below.

Step 3 Work with the ACCC to develop measures and targets which are linked to market impact and any other relevant measures. This is a longer term exercise which will form part of the process associated with finalising of the Statement of Regulatory Principles.

Table 11.1. Proposed Targets

Measure	Target Mean
Total number of events (loss of supply) greater than 0.2 system minutes (per quarter)	1.3 (summer), 0.8 (winter)
Total number events (loss of supply) greater than 1.0 system minutes (per month)	0.4 (summer), 0.07 (winter)
Static Var Compensator events (per month)	2.2
Equipment events per 1,000 circuit breakers (per month)	4.3
Secondary system events per 1,000 circuit breakers (per month)	3.1
Incident (human error) events per 1,000 circuit breakers (per month)	2.4
Total internal events per 1,000 circuit breakers (per month)	10.1
Total external events per 1,000 circuit kms (per month)	0.6 (summer), 0.4 (winter)

12 References

1. *Forecasting Capital Expenditure for the Queensland Transmission Grid – an Approach to Deal with a Rapidly Changing Power System*, Powerlink Discussion Paper (presented at a Powerlink Public Forum, 2 November 2000).

2. *Methodology for Incorporating Regulated Contracted Network Services into the Revenue Cap Determination*, Powerlink Discussion Paper (presented at a Powerlink Public Forum, 2 November 2000).

3. Sharp B., *Bulk Supply Point Reliability Indicators for Performance Contracts*, Distribution 2000 14-17 November, 1995, Brisbane, Australia.

4. Sharp B., *Monitoring System Reliability Using Statistical Methods*, CEPSI Conference, 1998.

5. Sharp B., *Correct Design and Use of Performance Indicators*, Third International Conference of Maintenance Engineering, 19-21 May, 1998, Adelaide, Australia.

6. Electricity Reform Unit, *Powerlink Queensland Regulatory Determination,* Queensland Government, Department of Mines and Energy, June 2000 (website address: http://www.dme.qld.gov.au/energy/eru/eru.htm).

7. Powerlink Queensland, *Annual Planning Statement 2000*, April 2000.

ATTACHMENT 1

Estimation of Additional Asset Risks Associated with New Queensland Gas Transmission Projects

ESTIMATION OF ADDITIONAL ASSET RISKS ASSOCIATED WITH NEW QUEENSLAND GAS TRANSMISSION PROJECTS

New Gas Era

Environmental imperatives are placing ever increasing pressure on energy consumers to substitute natural gas energy for other fossil fuel derived energy products. This pressure will intensify with time.

Because Queensland's energy consumption is so dependant on coal and coal produced electricity, legislative requirements for fuel substation will have a significant impact. In particular, the electricity transmission network, which has been purpose-built to deliver from coal fired power stations, is especially vulnerable to impacts on natural gas transmission.

Figure 1 – Existing Gas Transmission

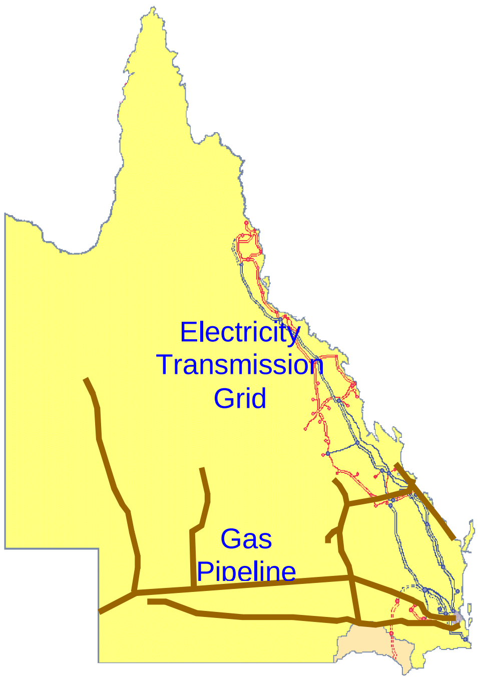


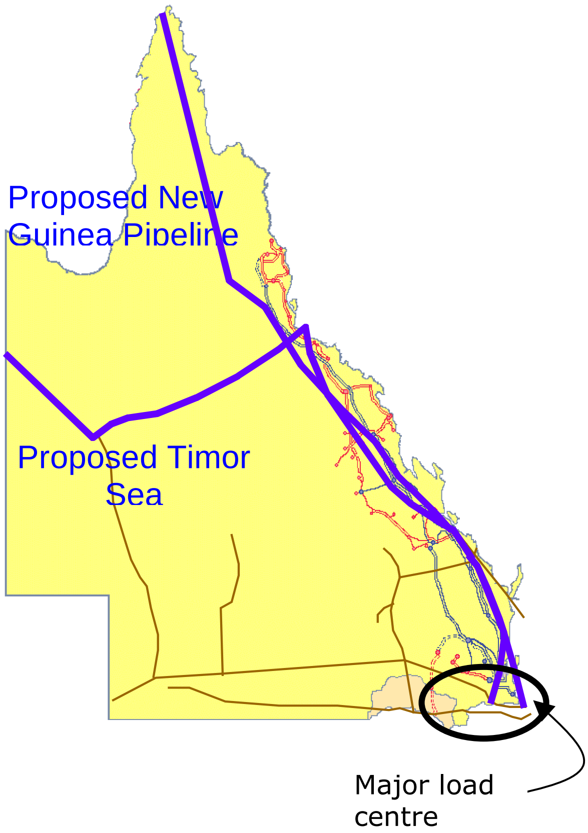
Figure 1 above shows the current Queensland electricity transmission grid as well as the gas pipeline transmission infrastructure. To date, the natural gas market is energy limited and traverses separate territory than does the electricity grid. That is, the existing gas grid and electricity grids are complementary.

However, two significant natural gas projects are presently being developed which will meet significant energy requirements of the state. Environmental imperatives will result in at least one of these projects proceeding. The "Queensland Energy Policy", a state government initiative, provides additional commercial and legislative drivers for an early transition to gas derived energy in Queensland.

The two projects are shown in Figure 2. Either project will have an impact on electricity transmission due to the vast new quantities of energy available, and due to the geographical closeness of the pipelines to the electricity grid.

Figure 2 shows that the pipelines run parallel to the electricity grid and are in direct competition with it.

Figure 2 – Proposed Gas Transmission



Electricity Transmission Risks

New natural gas transmission will impact on electricity transmission by reducing utilisation of the existing infrastructure. This reduced utilisation will result from:

- ♦ end use customers in particular regions totally or partially substituting gas for electricity;
- ♦ new gas fired embedded generators supplying directly into the distribution network; and
- ♦ new large gas fired generators supplying into the transmission grid at locations closer to load centres than the existing coal fired plant.

The above impacts will result in a less optimal transmission grid. This will over time result in assets being "optimised out" of the regulated asset base with consequential reduced returns to the owner. Even many new augmentations, which are subject to the same risks, must still proceed. Transmission entities are not able to defer their obligations even in the face of market uncertainties.

Higher Regulatory Returns

In determining appropriate returns on equity. The ACCC needs to acknowledge the added risk facing the Queensland electricity grid in the face of a growing gas market. In Queensland, the change is even more significant than in other states where significant gas markets exist and historic network development has taken account of the dual energy sources. Additionally, other states do not have gas/electricity grid parallelling to the same degree as the mooted Queensland developments.

Account can be taken of the additional optimisation (or stranding) risk by:

- ♦ allowing full depreciation on stranded assets (the DRP suggests this is possible where stranding can be identified in advance);
- ♦ increased rate of return to cover these specific risks.

In many cases where asset stranding occurs, or partial stranding (optimisation) occurs, advance warning is not possible. Often these events occur within a regulatory reset period which reduces any opportunity to flag these assets for write down. Therefore an additional risk premium is appropriate to cover the risks associated with those assets that cannot be flagged in advance for stranding.

Assessment of Equity Beta

To gauge the impacts of the future gas transmission on the electricity transmission business, a range of equity β's were derived which allowed the same rate of return to be earned on the business taking account of up to 40% additional asset optimisation.

The return analysis has been calculated using equations *[1]* and *[2]* below.

$$Return = RAB \; x \; WACC_{van} \qquad [1]$$

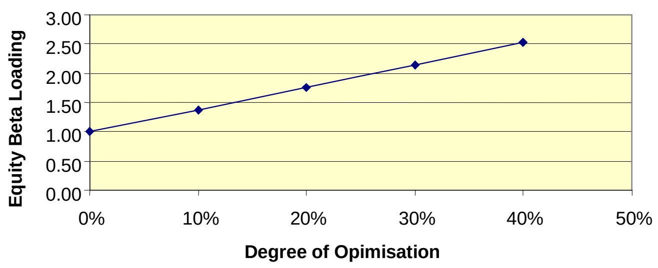
and

$$WACC_{van} = R_d \cdot \left[\frac{D}{V}\right] + [\mathrm{Re}] \cdot \left[\frac{E}{V}\right]$$

$$WACC_{van} = R_d \cdot \left[\frac{D}{V}\right] + [R_f + \beta_e.(R_m - R_f)] \cdot \left[\frac{E}{V}\right] \qquad [2]$$

Figure 3 below outlines the risk premium (equity beta) required for the various degrees of asset optimisation.

Figure 3 Estimate of Risk



While it is not possible to pre-estimate the impact of the gas projects on transmission optimisation, it is clear that even small impacts will require significant increases in the equity beta to ensure Powerlink is able to earn a reasonable return on its investments, commensurate with the risks involved. At the conservative end of the scale, an equity beta loading in the range 20% – 40% ought to be applied.

Alternative Approach

In Powerlink's Application for regulatory revenue determination, the asymmetric risk associated with optimisation resulting from gas transmission is factored in as an additional equity premium rather than of an equity beta loading. These alternative equity adjustment approaches are directly related as shown below in Figures 4 and 5 following.

Figure 4 Estimate of Risk Premium

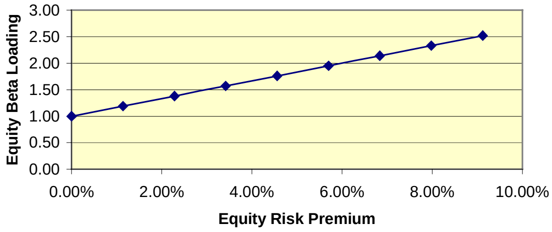
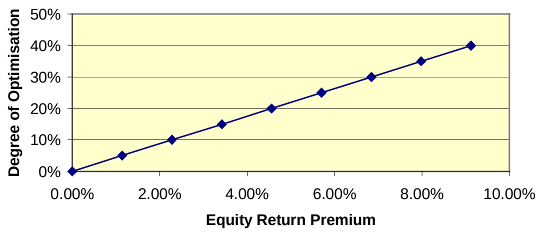


Figure 4 plot can be reconstructed to show the equity risk premium as a function of degree of optimisation, as shown in Figure 5.

Figure 5 Estimate of Risk Premium



Conclusion

In order to incorporate the additional market equity risk associated with new gas pipeline transmission within Queensland, an explicit loading in the WACC formulation is required. This loading can be accounted for either as a direct loading factor which applies to the equity beta or as a margin which is added to the return on equity.

Powerlink has adopted the latter approach and has included a risk margin adjustment of 1.3% to the return on equity component of WACC in its Application. This is considered conservative in terms of the identified risks.

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