Australian Competition and Consumer Commission

Transend Regulatory Review

Capital Expenditure and Asset Base
Operational Expenditure and Service Standards

Final Report

June 2003

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Executive Summary

The Australian Competition and Consumer Commission (the Commission) is conducting an inquiry into the appropriate revenue cap to be applied to the non-contestable elements of the transmission services provided by Transend Networks Pty. Ltd. (Transend) for the Regulatory Period (RP) from 1 January 2004 to 30 June 2009.

This report presents GHD's review of the Transend Revenue Cap Application in relation to Capital Expenditure (Capex), Asset Base Roll-Forward, Operating Expenditure (Opex) and Service Standards, as part of the Commission's review process. The review also included an independent load forecast undertaken by ACIL Tasman (AT), due to the uncertainties relating to the entry of Transend into the National Electricity Market (NEM) prior to the completion of the Basslink project.

The review has been undertaken within the Commission's defined scope and is to be used only for the purposes of the Commission's Revenue Cap Decision. The review relies on information provided by Transend and does not include verification of the information by GHD. Unless stated otherwise, ACIL Tasman does not warrant the accuracy of any forecast or prediction in the independent load forecast due to uncertainties in future market behaviour.

The key findings of the review are:

Operating Environment

Major changes have or will occur in Transend's operating environment, including natural gas competition for energy, NEM entry and wind power development, which collectively create significant uncertainties for Transend in terms of management and operations, forecasting loads, ensuring system reliability and identifying appropriate levels of future Capex and Opex. Consequently, Transend will be required to undertake new activities to meet the responsibilities of operating in a wider and more complex market, and the increased activity in Tasmania by generators. Conversely, the market changes are intended to increase competitive pressure on all market participants and provide benefits to customers in terms of reduced net prices for energy services and/or increased service performance: these aspects will need to be considered by Transend in its operations and planning.

Overall Comment on the Application

The Application generally provides an extensive description and supporting reasons for Transend's expenditure proposal over the RP, and supplies information on expected costs and revenues at a high level. The Application has been based on a 'building block' approach in accordance with the Commission's Draft Regulatory Principles. The application did not include detailed breakdowns of cost elements or sufficient historical costs to enable the reader to gain an appreciation of trends, the impact or significance of each element described. Transend may provide further information into the public domain. Transend provided GHD, largely on a confidential basis, detailed cost breakdowns and some historical information.

While Transend has put a substantial amount of effort into developing its Revenue Application on a 'cost plus' basis, its approach has not been sufficiently underpinned by adequate operational cost efficiencies, or budget rationalisation processes which include detailed information about cost-benefit analysis of overall programs or risk-based assessments of options for improvement.

Given Transend's position as a monopoly service provider, these aspects are critical, especially to support its Application.

It is difficult to assess the 'right' level of investment in a review process such as this: it needs to be determined on the basis of detailed discussion, debate and rationalisation between Transend and its stakeholders, using an appropriate level of understanding of risk, cost and service performance in each instance (eg. program or major project).

Historical Context and Trends in Revenue

The Application outlines that a key Opex influence is NEM entry, which includes many additional activities such as the duplication of System Controller functions, market entry and participation activities, wholesale metering, communications and performance reporting. The Application also details other major Opex influences of increased maintenance spending, and connections and development activity.

Transend also proposes a significant Capex program, which generally increases the levels of investment achieved in past years. The Application's basis for this program is a combination of a backlog of development projects to meet growth, compliance and reliability drivers, and renewals of assets that have become obsolete or have reached the end of their serviceable life.

The combined effect of the Opex and Capex proposals in the Application is a significant increase in revenue from historical levels. However, it is difficult for stakeholders to assess the service benefits that may flow from the proposed substantial increases in revenue.

Independent Load Forecast

The ACIL Tasman (AT) forecast is for growth in annual electricity requirements of 0.7% p.a, which is lower than the growth of 1.9% per annum recorded over the past decade. This is mainly because the minor stimulatory effects on the economy from the introduction of natural gas are more than offset by the loss of space and water heating loads to gas in the residential and small business sectors. AT also forecasts an increase in winter peak demand of 0.8% per annum.

Compared with other forecasts, the AT forecast of energy growth is slightly less than the SKM and Aurora (without gas) forecast growth of 0.9% per annum and the Transend extrapolated growth of 1.0% per annum.

There is however variation in the regional and substation forecasts between AT and Aurora (without gas). The AT forecast has higher growth generally in the north and west than the Aurora (without gas) forecast and generally noticeably lower growth in the east and south regions of the State. These differences in the regional load forecast have potential to reduce the capital investment plans of Transend in some regions and increase it in others, although generally a minor number of megawatts is involved. The use of the Aurora (without gas) forecast by Transend for substations is considered reasonable.

The pattern of generation at peak times is forecast by AT to continue to be dependent on water storage conditions and rainfall pattern at least until interconnection with Victoria.

Basslink is expected to marginally reduce the energy required from Tasmania's hydro stations but is expected to contribute some 500MW to the Tasmanian peak load, causing more intensive hydro usage at peak times. Existing and planned wind farms will also reduce the need for energy production by the Tasmanian hydro plants, but the contribution of wind farms to the winter peak is uncertain as they are dependent on prevailing wind conditions, and hence they have not been included as contributing to meeting the peak demand. Ideally from a market perspective the transmission system should have the capacity to allow any pattern of generation that is available at the time.

Benchmarking

Benchmarks have been considered in terms of output benchmarks and process benchmarks. The brief process benchmarking assessment is part of the Asset Management review component below.

The overall assessment is that Transend is currently a lower to middle cost Transmission Network Service Provider (TNSP), with below average performance and significant shortfalls in terms of efficient investment decision-making capability. This indicates a need for Transend to focus on value outcomes by applying a higher level of rigour to cost/risk/service level trade-offs in investment.

With respect to output benchmarking, in considering a range of reports and Opex-based benchmark measures, Transend appeared as a lower to middle cost TNSP when compared nationally, based on either 1999/2000 or 2001/2002 revenue figures. The conclusions of these benchmarking studies change significantly if benchmarks are reviewed using Transend's Application forecasts over the RP. Transend's position, using a range of Opex-based benchmark measures, shows a rapidly increasing trend compared to other TNSPs for the period to 2005-06, then stabilising in later years as one of the highest cost TNSPs. No comparison has been made on total revenue, due to the difficulty in normalising for individual differences in TNSPs.

Asset Management

Transend appears to have an appropriate structure to effectively manage its business under the "asset manager / service provider" model, which is common in private utility businesses and separates the asset manager from the service provider through a performance agreement. Transend is further developing this model to provide for future changes to its operations on NEM entry. The organisation appears to have a strong technical and service culture, but with a low emphasis on cost efficiencies and the need to consider cost impacts in all decisions. An increased focus on the commercial aspects of the business and cost efficiencies is considered necessary, in terms of both organisational objectives and culture.

Transend has carefully considered the technical processes and interactions that apply within the organisation, but has not adequately addressed the commercial aspects that are also critical to deriving expenditure forecasts within a regulated environment. In particular, the budget rationalisation processes incorporating risk-based cost and service level tradeoffs are not well developed.

Transend's asset management documentation is in a rapid state of development. Numerous documents have been prepared which are based on best practice and compare with other TNSP's. Many documents are still to be developed, reviewed and updated, or coordinated. Many of the programs or practices referred to in the documentation are yet to be implemented.

The need for a significantly improved Asset Management Information System is acknowledged. The absence of decision support systems was particularly noted which impedes achievement of best practice economic asset management decision-making. Similarly, while Transend has reasonably comprehensive asset technical, condition and cost data sets for most assets, areas of shortfall occur in further decision-making data and knowledge, including failure consequence data and performance information. The absence of this information hampers Transend's ability to undertake necessary risk-based analyses and enable rationalisation decisions to be soundly based.

Capital Expenditure

GHD is of the opinion that a technically supported but unrationalised Capex forecast is as set out in Table E1-1. The values should be considered a maximum, except for development projects which have passed the regulatory test. Transend has not followed an adequate cost-risk trade-off or budget rationalisation process involving its customers, nor have the reliability impacts of any project been quantified. This means that the Capex rationalisation process must be undertaken on a subjective basis as part of the Commission's decision. The effect of an appropriate rationalisation process could be deferrals of projects or lower cost/service level solutions to projects, resulting in possible reduction in total Capex over the RP, in consultation with key stakeholders. This provides flexibility to Transend in its forward Capex program.

Table E1-1 Technically Supported Maximum Capital Expenditure (2002-03 $m)

	Jan to Jun 2004	2004-05	2005-06	2006-07	2007-08	2008-09	Total
Development							
- Fixed	2.8	43.2	10.3	45.8	4.6	2.5	**109.2**
- Variable	0	5.9	0.7	5.4	0.6	0	**12.6**
Total Development	2.8	49.1	11.0	51.2	5.2	2.5	**121.8**
Renewal	16.9	29.9	38.6	38.6	35.8	29.5	**189.3**
Reallocation of Refurbishments	0.6	1.1	1.2	1.1	1.1	1.1	**6.2**
Non-network	6.8	6.0	5.0	1.2	1.4	3.2	**23.6**
GHD assessed Total Capex	**27.1**	**86.1**	**55.8**	**92.1**	**43.5**	**36.3**	**340.9**

The basis for the above analysis is summarised below.

- Processes for technical assessment of Capex appear to be reasonable. The majority of projects have been based on an appropriate option to meet objectives and appear to be appropriately timed. Cost bases for Capex estimates are appropriate as are project delivery mechanisms for Capex. Transend has been through an internal process of budget rationalisation which appears to be based on both a practical assessment of the capacity of Transend to undertake the proposed programs, and an overall check of the revenue expectations of the organisation. GHD is of the opinion, however, that business decisions generally need improvement in areas such as risk-based assessment and identifying the impact of deferring project implementation. There does not appear to be sufficient consideration providing alternative levels of service, in order to provide a rational basis for deciding tradeoffs between cost, timing and risk in conjunction with stakeholders.
- While there has been in-principle agreement to Transend's security and planning criteria by Aurora and Hydro, concerns were expressed that the impact of these criteria on Transend's capital program needed identification before sign-off. There was no evidence that other customers were involved in this process, but this may be disputed after NEM entry by interested parties. Transend has used these security and planning criteria as the basis for development of its capital expenditure projection. The overall magnitude of the impact of its criteria on the capital expenditure is not possible to define until some agreement on the criteria to be applied is reached. Transend has advised that the majority of the forecast renewal is to maintain present levels of reliability rather than improve it. To determine the validity of this statement would need a detailed study, which is beyond the scope of this review.

- Fixed Development Capex appears to be appropriate from timing, costing and technical content. Two projects are concept only and timing is yet to be determined, however as they are technically justified it would be unlikely that Transend will delay these projects beyond the RP.
- Variable Development Capex projects have not been costed or scoped to the same detail as the fixed projects. The total forecast expenditure over the RP is $149.6 million. Using a weighted probability of project occurrence this reduces to $59.7 million. The Commission has directed GHD to establish a reasonable level of variable Capex based on a weighted probability of occurrence. The projects associated with generation connection appear to have specific beneficiaries and would be unlikely to pass the market benefits assessment of the Regulatory Test. Consequently, they have been removed in GHD's assessment of Variable Capex. Projects based on high load forecast scenarios are also recommended for removal.
- Renewal Capex has usually been developed on the basis of condition assessments, but some asset renewals forecasts remain as age-based. The overall renewals forecast is less than what would be expected on age-based assessment alone. GHD is of the opinion that the renewal Capex should be adjusted for potentially extended life of some assets. An error in the substation development costs for one development also reduces the allowance in 2008/09 by $2.5 million. Transend is expected to rapidly develop new approaches to renewals through implementation of new technology, which will deliver reductions in Renewals Capex over the RP, although the effect of this on costs is not possible to determine and hence no reductions have been made.
- GHD has made an additional allowance of $6.2m in Capex for refurbishment projects which were considered by Transend to be Opex under its Capitalisation Policy, but which GHD considered should be Capex.
- Non-network Capex has been extensively reviewed. After adjustment for an omission for vehicle trade-ins and reduction of some contingency items and allowances, a net reduction of $3.18 million is considered appropriate. Similarly to renewals, GHD expects that more cost-effective solutions will be developed to address some Non-network projects, and the recommended reductions should have minimal impact on Transend's ability to deliver planned improvements.
- Transend is considered capable of delivering the projects in the suggested GHD Capex forecast, based on recent performance. This does not allow for delays in external factors such as planning or environmental approvals. These aspects are unable to be defined or estimated.

Operating Expenditure

Due to the significance of the proposed Opex increases, a number of approaches were used to assess the reasonableness of Opex, including:

- Review of historical trends and patterns in expenditure
- Analysis of cost category breakdowns and detailed review of selected expenditure groups.

- Alternative approach to cost build-up using a combination of trend prediction on base activities and allowing for new or fully justified additional activities
- Consideration of industry benchmarks.

GHD has undertaken a considered assessment using these tools that result in an alternative Opex proposal being suggested, as summarised in Table E1-2.

Table E1-2 GHD Suggested Alternative Opex Proposal (2002-03 $ millions)

	03/04 6 months	04/05	05/06	06/07	07/08	08/09	Total
Transend Application	16.0	33.4	36.5	36.9	35.0	35.2	193.0
Suggested Adjustments	-2.9	-3.6	- 5.6	-7.2	- 7.8	-8.1	-35.2
GHD Review	**13.1**	**29.8**	**30.9**	**29.7**	**27.2**	**27.1**	**157.8**

GHD's alternative Opex forecast has been determined from an average historical base of $18.5m p.a. for ongoing core activities, less the application of a 2% p.a. cost efficiency performance indicator, and allowing for the 'cost plus' associated with new activities such as increased substation maintenance, vegetation control and additional Transmission Line inspections, telecommunications, NEM preparation and participation costs, increased insurance premiums, system control overheads unrecovered, dismantling charges and other minor items. In summary the alternative trend analysis represents a recommended reduction in Opex of $35.2m for the RP. This is a reduction of around $6.4m average p.a. from the Transend Application.

This assessment has been developed after the following key findings:

- Transend has developed its Application by a detailed text explanation to support its high level forecasts. The Application contained limited historical data and cost breakdowns to enable the reader to analyse the significance of proposed new activities. It is recommended that the Commission lay out the form of presentation and the support data that is required for future Applications to facilitate an appropriate review process.
- Transend has provided detailed explanations in the Application as to where efficiency gains may be achieved in the future, but did not support these comments with any calculations as to how efficiency gains have been built into the Opex forecasts.
- Following provision of limited historical data and comparison with the Application forecasts, the Application shows that Opex costs will rise from $19.37m in 2000/01 (2002/03 real) to $34.61m (2002/03 real) at the end of the RP 2008/09, an increase of 78.7%.

- The increase in the Application forecast Opex during the RP is due primarily to two major factors: (i) Transend's NEM Entry /Basslink at a cost of $30.28m over the period 2002/03 and 2008/09, with a projected ongoing annual cost thereafter of $5.38m p.a; and (ii) increase in maintenance as a result of Transend's 'bottom up' review of the current condition of all its transmission assets and the need to employ additional staff to improve the general management of Transend during RP.
- Processes for technical assessment of maintenance Opex appear to be reasonable and the majority of the work is technically supported by reasoned argument or condition-based assessment. Additional consideration is required providing for alternative levels of service and residual risk assessment, in order to provide a rational basis for deciding tradeoffs between cost, timing and risk in conjunction with stakeholders.
- The transfer of the System Controller into Transend's cost structure incurs an increase in costs as a result of the decision to maintain a System Security process backup that mirrors the NEM control system. The maintenance of the duplicate system was reviewed and deemed appropriate by the Tasmanian Government when the NEM/Basslink was approved.
- The application of grid support costs is so uncertain that a pass-through allowance is most appropriate, subject to certain conditions. These conditions should require that Transend justifies the amount of pass-through requested each year, and demonstrates that the lowest net cost option was selected for the project, including grid support costs.

Regulatory Asset Base Roll Forward

The development of the opening regulatory asset base (RAB) as at 1 January 2004 is accomplished by rolling forward the value of the opening asset base as determined by the jurisdictional authority as at 30 June 2001 using an appropriate index, and including prudent capital additions and disposals, and depreciation over the relevant period. Transend proposed a RAB and supported its Application with spreadsheets showing its proposed RAB derivation. GHD has reviewed the Application and supporting information and finds that:

- Assets have been appropriately categorised.
- CPI indexation was generally appropriate except for one error, for which an adjustment of -$0.3m has been made.
- Depreciation profiles appear appropriate and are consistent with other TNSPs.
- No inconsistencies were found in spreadsheet capital additions and deletions when compared to sample project amounts provided separately by Transend.

- Land and easement costs, comprising both compensation and acquisition costs, are not depreciated but indexed at CPI for roll forward. This is in accordance with previous Commission decisions for compensation costs, but not for acquisition costs, which GHD considers should be depreciated with the constructed assets at the relevant site. This has resulted in a $5.8m adjustment being recommended.
- The roll forward is based on projected Capex reaching ‘in-service’ status by 31 December 2003. GHD recommends that the additions ending 30 June 2003 be confirmed by Transend at the end of the 2002-03 financial year, along with any adjustments to the projection for the period to 31 December 2003, and those details be included into the roll forward.

Table E1-3 shows the schedule comparing the opening asset base at 30 June 2001 and the estimated asset roll forward as at the 31 December 2003 as adjusted and recommended by GHD.

Table E1-3 Recommended Asset Base Roll Forward 1 July 2001 to 31 Dec 2003 (in nominal $ millions)

Item	Opening asset base as at 30 June 2001	Opening Regulatory Asset Base for 31 December 2003
Substations	190.2	249.6
Transmission lines and cables	209.3	220.6
Protection and Control	42.2	34.6
Refurbishments	0	8.8
Land and Easements	66.1	65.1
Other assets	13.8	18.9
Total	**521.6**	**597.6**

The Commission’s attention is also drawn to some issues revealed during the review:

- Allowance in the opening asset base at 30 June 2001 for estimated land and easement acquisition costs amounting to $66.1m, see Table 8-2 for detailed breakdown.
- Considering the future treatment of assets which have been fully depreciated, then revalued and reinstated in the asset base as at 30 June 2001.

Performance Incentive Scheme

Transend proposes a Performance Incentive (PI) scheme which is in line with an industry study undertaken for the Commission.

The selection of service indicators by Transend for the PI scheme is considered appropriate. Events caused by Basslink or other market network service providers should be excluded.

GHD concludes that the proposed PI Scheme does not appear to be particularly challenging when compared with past performance, although historical data is limited. Recently completed equipment reliability projects may contribute to long term improvements in availability, but Transend was not able to quantify this impact. New proposed Capex may improve long term availability of the system, while in the short term, the increased Capex and maintenance programs proposed will increase the need for planned outages and may have some adverse effect on performance. No information was provided to GHD to quantify the net impact of these future changes. There is identified scope to improve service performance using improved work practices.

An alternative PI scheme is suggested which could remain revenue neutral on the basis of making some allowance for reasonable improvements in performance due to investment, maintenance and improved practices. While not particularly challenging, the alternative scheme is considered more appropriate as a means of implementing a PI scheme in the absence of longer term performance data or any analysis of past performance improvements or future expectations by Transend.

Efficiency Bonus

Transend proposes an Efficiency Bonus of $1.5 million applied to the RP on the basis that Transend has increased its scope of work over the previous revenue period as a result of largely NEM entry and regulatory activities. GHD has provided a suggested Opex trend which includes allowances for new tasks undertaken by Transend. The basis on which an efficiency bonus is payable in addition to claimed Opex is thus difficult to assess considering that the basis for Transend's proposed efficiency bonus is costs incurred in the previous revenue period. Consequently, GHD cannot recommend the allowance of an efficiency bonus.

1. Introduction

1.1 Introduction

Under the National Electricity Code (NEC), the Commission is responsible for regulating the non-contestable services of the transmission network service providers (TNSPs).

Tasmania has agreed with the Commonwealth Government to enter the NEM, subject to the successful completion of Basslink. It will confer the (regulatory) powers and functions to the Commission, in accordance with Section 44ZZM of the *Trade Practices Act 1974* (TPA), to enable the Commission to set a revenue cap as if Tasmania were in the NEM. The Tasmanian legislation is expected to be finalised in mid 2003.

The Commission is conducting an inquiry into the appropriate revenue cap to be applied to the non-contestable elements of the transmission services provided by Transend for the period from 1 January 2004 to 30 June 2009, referred to herein as the Regulatory Period or RP. The Commission will make its decision in accordance with its responsibilities under the *Tasmanian Electricity Supply Industry Act 1995* and associated regulations (Tasmanian legislation) and the TPA.

Transend has made its Application to the Commission proposing a revenue cap.

As part of the inquiry, a capital expenditure (Capex) and asset base, and operational expenditure (Opex) and service standards review is required to assist the Commission in assessing the performance of Transend relative to the requirements of the TPA and the Tasmanian legislation. The Commission has been informed that the Tasmanian Electricity Code (TEC) mirrors the provisions of the NEC. Part B of Chapter 6 of the NEC requires, *inter alia*, that:

- In setting the revenue cap, the Commission must have regard to the potential for efficiency gains in expected operating, maintenance and capital costs, taking into account the expected demand growth and service standards.
- The regulatory regime seeks to achieve an environment which fosters efficient use of existing infrastructure, efficient operating and maintenance practices and an efficient level of investment.
- In this context, GHD has been engaged to inform the Commission on the:
  - Appropriateness of Transend's method to forecast Capex and budgets (including the methods Transend will use to check the reasonableness of the results).
  - Adequacy, efficiency and appropriateness of the actual Capex projects planned by Transend to meet its present and future service requirements.
  - Adequacy, efficiency and appropriateness of the Opex stated by Transend as being necessary to meet its present and future transmission service requirements.

- Appropriateness of the roll forward of the asset base to 1 January 2004, based on the opening RAB valuation of Transend determined by the jurisdictional authority as at 30 June 2001.
- Appropriateness of the performance incentive scheme proposed by Transend.
- As part of the review process, ACIL Tasman has undertaken an independent load forecast, due to the uncertainties relating to the entry of Transend into the NEM prior to the completion of the Basslink project.

1.2 Terms of Reference

The Terms of Reference require the consultant to review the following matters:

Capital Expenditure

Critically analyse and comment on Transend's assumptions, methods and findings. In particular, the review should address the:

- assumptions regarding materiality,
- method for determining the adequacy of the system for present and future,
- findings in relation to the security and reliability of the system,
- effectiveness of the asset management system ensuring that only necessary and efficient Capex is undertaken,
- effectiveness of capital works assessment criteria and process to identify and evaluate alternatives to proposed Capex (including embedded generation, cogeneration, demand side responses and other non-build alternatives), and
- findings in relation to the appropriateness of the major proposed capital works and their anticipated costs.
- in relation to Transend's method to forecast Capex, the review must assess and comment on proposed scenarios and budgets, including the:
  - methods used to check the reasonableness of the forecasts and related expenditure,
  - allocation of individual Capex projects to each scenario, and
  - identification of cost-effective alternatives to the proposed expenditure.

Asset base

The consultant must arrive at the opening RAB on 1 January 2004 by rolling forward the value of the asset base determined by the jurisdictional authority as at 30 June 2001 to the opening regulatory period using an appropriate index. The review is to include a schedule listing the assets categorised into classes, standard replacement costs, relevant (asset) lives, depreciation profiles and any optimisation adjustments.

Operational Expenditure

Analyse and comment on Transend's Opex and the delivery of its transmission services, including:

- an assessment of Transend's controllable Opex for each year during the regulatory period and the scope for efficiency gains.
- an assessment of Transend's Opex against current available indicators, with a view to improving and implementing benchmark indicators and targets, based on key controllable costs and with reference to national and international best practice.
- the appropriateness of Transend's allocation of Opex to specific activities, including the separation of: regulated and non-regulated activities; routine maintenance and renewals; and the treatment of joint and common costs, especially corporate administration expenses, financing charges and depreciation.
- the effectiveness of Transend's operating practices and asset management system in ensuring that only necessary (and efficient) Opex is incurred with particular reference to factors such as asset base, Capex and the operating environment.
- in the context of benchmarking, the degree to which this should account for differences in network age, design and configuration, operating environment, service standards and economies of scale.
- comment on the internal and external factors that may affect the level of Opex over the regulatory period commencing 1 January 2003.

The review will also recommend appropriate service standards and performance targets, based on Transend's historical performance and the previous review by Sinclair Knight Merz.

1.3 Review Methodology

The review has been undertaken in accordance with the Terms of Reference (ToR) and on the basis of the general tasks outlined below:

- Review of application and appropriate Commission documentation.
- Provision of a questionnaire and information request to Transend.
- Review of documentation and responses provided by Transend.
- Conduct of independent load forecast, via ACIL Tasman, using its PowerLink model of the NEM.
- Conduct of discussions and interviews with relevant Transend staff to develop understanding and analyse the information provided to meet the ToR.
- Further communication and information requests to clarify and justify the information provided.
- Preparation of a draft report for review by the Commission and Transend.

- Consideration of review comments and incorporation of appropriate amendments into a final report.
- Communication with stakeholders and provision of responses as required.

1.4 Glossary of Terms

A Glossary of Terms and Acronyms is included as **Appendix A**.

1.5 Statement of Limitations

This report is only to be used for the exclusive purposes of the Commission's Revenue Cap Review of Transend and cannot be used or referenced for any other purpose. This report is supplied in good faith and reflects the knowledge, expertise and experience of the consultants involved. GHD accepts no responsibility whatsoever for any loss occasioned by any person acting or refraining from action as a result of reliance on the report, other than the Commission.

The review has relied upon the information supplied by Transend during the course of the review process. The review has not involved the verification by GHD of data or information supplied by Transend except in limited instances.

A list of references is provided in **Appendix B**.

In conducting the independent forecast in this report ACIL Tasman has endeavoured to use what it considers is the best information available at the date of publication, including information supplied by the Commission. Unless stated otherwise, ACIL Tasman does not warrant the accuracy of any forecast or prediction in the report. Although ACIL Tasman exercises reasonable care when making forecasts or predictions, factors in the process, such as future market behaviour, are inherently uncertain and cannot be forecast or predicted reliably.

1.6 Acknowledgements

GHD acknowledges the assistance provided by the Commission and numerous senior staff of Transend in undertaking this review.

2. Transend and Its Application

2.1 External Operating Environment

Transend currently operates under a State-based regulatory regime, with a vertically separated industry into generation (Hydro Tasmania and Bell Bay Power Pty Ltd), transmission (Transend), and distribution and retail (Aurora Energy Pty Ltd), except for the Bass Strait islands. All the above companies are fully State-owned enterprises, formed from the disaggregation of the Hydro Electric Commission (HEC) on 1 July 1998. The Regulator is the Office of the Tasmanian Energy Regulator (OTTER), and each business operates under a Licence.

With the completion of the Basslink project, electricity will be able to flow to and from the mainland of Australia, and Tasmania will enter the NEM prior to completion of the project. The NEM is regulated by State-based regulators for generation, distribution and retail services and by the Commission for transmission services. NEMMCO, the National Electrictricty Market Management Company, manages the national network load allocation.

This new operating environment gives rise to new competition challenges from which Tasmania was previously isolated. Under this environment, extended possibilities exist for developing new sources of energy in Tasmania especially through wind power, to supply the mainland and new development in Tasmania. New energy competition in the form of natural gas supply to Tasmania has also recently occurred.

It is recognised that these major changes in the external environment create significant uncertainties for Transend in terms of management and operations, system planning and reliability and identifying appropriate levels of future Capex and Opex. Consequently, flexibility needs to be built into programs to manage the range of possible outcomes which may occur. Transend will be required to undertake new activities to meet the responsibilities of operating in a wider and more complex market, and the increased activity in Tasmania by generators. Conversely, the changes are intended to increase competitive pressure on all market participants and provide benefits to customers in terms of reduced net prices for energy services and/or increased service performance: these aspects must also be considered by Transend in its operations and planning. This is especially so given the monopoly position of TNSPs for non-contestable services.

2.2 Corporate Environment

Transend is still undergoing rapid change as a State-owned company. It commenced operation in 1998 with some 46 employees and has grown to some 120 employees at present, and is projected to increase to about 140 by 2008/09. It is recognised that Transend was under-resourced at the time of disaggregation. It has had past difficulty meeting customer needs in terms of responses to connection enquiries, and has been unable to meet its approved allocation for development and renewals Capex (as advised verbally by staff, implied in terms of “catch-up” tasks in the Application and confirmed by other stakeholders).

The company is structured under an asset manager / service provider model with the core process groups being Network, Connections and Development, System Controller, and TWEM (Tasmanian Wholesale Energy Market) and support process groups being Finance and Business, Human Resources and Legal and Contracts.

The System Controller is a ring-fenced entity within Transend Networks, appointed under the Tasmanian Electricity Code and Electricity Supply Industry Act 1995, being responsible for overall control of the Tasmanian electricity supply, by managing the dispatch of generation, maintaining system security and contributing to system planning. The costs are presently borne by the three electricity businesses in Tasmania. On entry to the NEM, the System Controller functions will be transferred to NEMMCO but it appears that local system control for 110kV and lower voltage systems and a backup total system security capability will be required. These functions will be transferred to Transend’s proposed Transmission Operations Group. This will impose some additional costs on Transend.

TWEM is a specific group formed to manage issues associated with NEM entry.

A new Market and Regulation Group is proposed in 2003-4 to oversee Transend’s regulatory strategies and policies, assuming functions from a number of present groups.

The costs associated with each of the above groups are broken down and reviewed in detail in Section 7.

2.3 The Application

Transend Revenue Cap Application comprises:

- Revenue Cap Application for the period 1 January 2004 to 30 June 2009 document
- Supporting Appendices
- Application proformas in Excel spreadsheet form.

The Application generally provides a description and supporting reasons for Transend's expenditure proposal over the RP, and supplies information on expected costs and revenues at a high level.

The Application did not include detailed breakdowns of cost elements or historical costs to enable the reader to gain a strong appreciation of proposed cost element magnitudes and trends. This information was sought from Transend and subsequently provided to GHD for the review on a confidential basis. The Application was further supported by the Transmission System Management Plan, which provided major input to understanding the asset management context underpinning much of the Application, again on a confidential basis.

After extensive discussions, Transend indicated that it proposes to provide additional qualitative and quantitative data for public viewing to support its Application. Initial Transend advice was to withhold the data at detailed level primarily on the basis of business confidentiality. For reasons of transparency, as Transend is a monopoly, GHD considers it is incumbent upon Transend to make its stakeholders aware of the financial costs associated with the existing and proposed new activities. This includes providing enough detail and historical context so that the impact of each significant activity can be seen in financial terms. Selected commercially sensitive data would, of course, be rolled up to a higher level to avoid disclosure. However, in GHD's opinion, this should be kept to a minimum.

It is anticipated that the additional information will be made available to interested stakeholders via the Commission Website (www.accc.gov.au).

2.4 Key Issues

Key issues to be considered in reviewing the Application, relating to Transend and its operating environment, include:

- Flexibility built into programs to manage the range of possible outcomes which may occur under uncertain future conditions over the RP.
- Consideration in operations and planning of benefits to customers in terms of reduced prices for energy services and/or increased service performance.
- Transend claims to have some of the oldest transmission assets in Australia, with transmission lines averaging 43 years and substations averaging 36 years.
- An extensive transmission system is required, despite the small size of Tasmania, due to the relatively large number of predominantly hydro power stations (28) connected to the system, their geographical spread, and the dispersion of load centres.
- Transend manages a system of generally lower voltages than other TNSPs in Australia. Most others do not operate below about 110kV, whereas Transend has 88kV transmission lines and provides voltages to customers as low as 6.6kV. Consequently, Transend has a wide diversity of operating voltages that compounds operations and maintenance and impacts adversely on operating costs when compared with other TNSPs.
- Transend has a lower level of firm connections than other TNSPs, meaning that Transend has a lower level of system security or redundancy provided in the event of system failure. Transend is thus more likely to be subject to availability problems than it would be with additional redundancy built into its systems.

3. Load and Generation Forecasts

3.1 Introduction

This section of the report summarises the findings of an independent forecast of Tasmanian electricity requirements prepared by ACIL Tasman (AT). The full AT report may be viewed at **Appendix C**.

Transend's forecast of future capital expenditure in its Application is based on a load forecast prepared by Sinclair Knight Mertz (SKM) in March 2003 which is very similar to the substation load forecast (without gas) for Aurora Energy prepared by RM Witney PL and New Generation Consulting in February 2003. Comparison is made with other forecasts as follows:

- Electricity Supply Association of Australia (ESAA) forecast by NIEIR.
- Transend forecast by NIEIR.
- Aurora Energy Substation forecasts (with gas introduction and without gas).

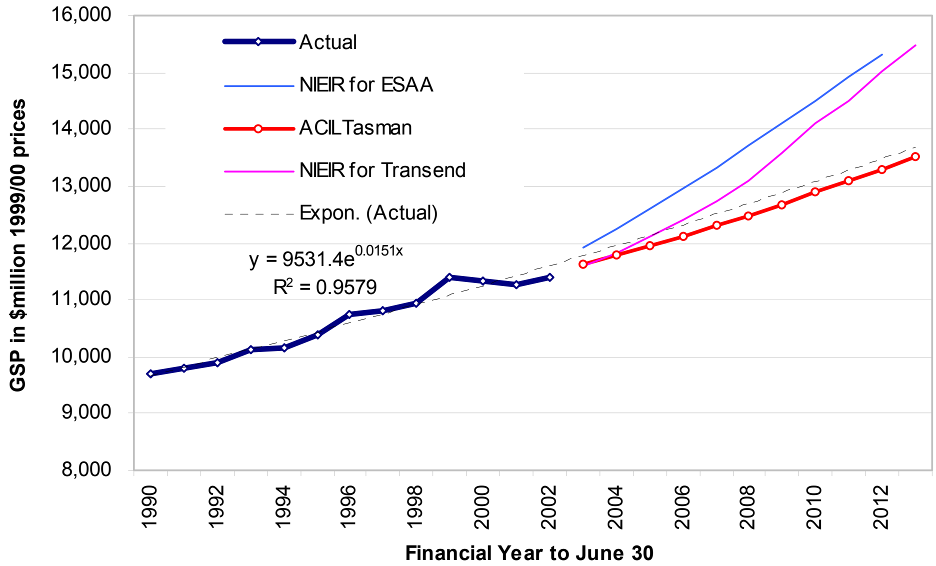
3.2 Underlying Factors

The load forecast undertaken by AT is based on an examination of past trends of annual energy and peak demands in Tasmania and underlying factors including economic growth, population growth and household formation, comparative energy prices, and major developments such as Basslink and the introduction of natural gas to Tasmania.

3.2.1 Economy

Growth in the Tasmanian economy since 1989/90 has averaged 1.5% per annum the same as the growth forecast by AT forecast. The positive effect of the introduction of natural gas is expected to offset the fact that Tasmania no longer has the low cost hydro generation capacity to continue to attract large electrical intensive loads. The AT forecast of economic activity is shown in Figure 3-1.

Figure 3-1 Actual and Forecast Economic Activity in Tasmania ($1999/00)



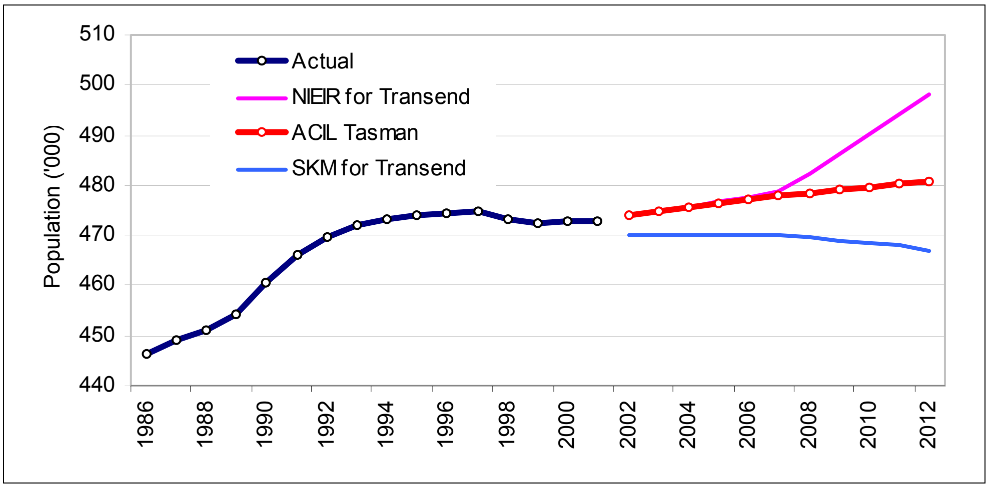
Data source: Historic data from ABS

3.2.2 Population and Households

Population growth has three components; natural increase, net overseas migration and net interstate migration. AT expects this downward trend in natural increase in Tasmania to continue but at a reduced rate. The net overseas migration to Tasmania is slightly positive and AT is forecasting this to continue. The net interstate migration to Tasmania has been generally negative over the past 15 years and AT expects this trend to continue.

Overall population growth is expected to be slightly positive over the forecast period with the positive effects of natural increase and net overseas migration just offsetting the loss of persons to interstate. Figure 3-2 compares the AT forecast of population with the forecast prepared by NIEIR and SKM.

Figure 3-2 Comparison of Population Forecasts



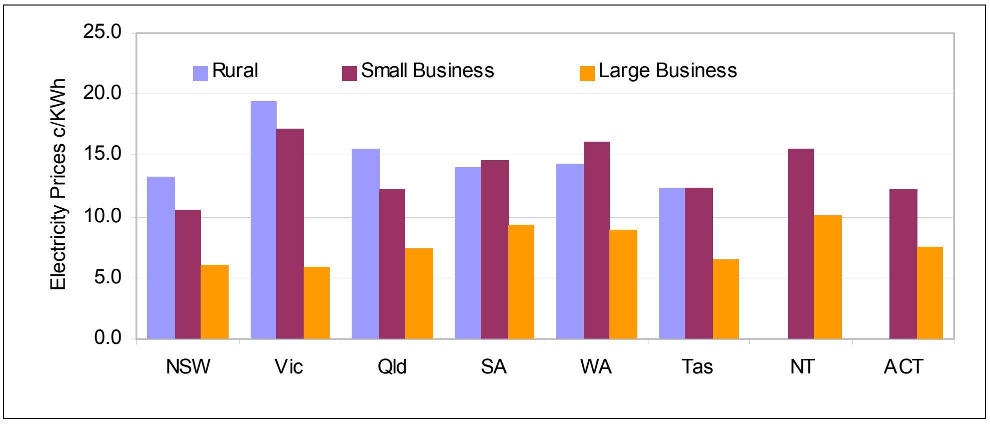
AT is forecasting a decline in the number of persons per household in Tasmania of 2.48 to 2.24 by 2012, which results in an increase in the number of households in Tasmania from 191,000 currently to around 215,000 by June 2013.

3.2.3 Electricity and Gas Prices

Data from the Australian Bureau of Statistics shows that the price of electricity in the Tasmanian residential sector has increased more than other fuels and more than CPI. According to the ESAA, between 1995/96 and 2000/01, the residential electricity prices in Tasmania have increased from among the lowest at 9.14c/KWh to be in the mid range at 11.54c/KWh.

Electricity prices for small business, large business and rural users in Tasmania are close to the lowest in Australia as shown in Figure 3-3.

Figure 3-3 Business and Rural Electricity Prices by State 2000/01



Data source: ESAA

Electricity Price Outlook

The notional electricity spot price in Tasmania on 28 March 2003 was $122.77/MWh that is well above the pool prices prevailing in the NEM.

Detailed modelling of the NEM by AT suggests that beyond 2005 pool prices will tend to be in the $30 to 40/MWh range providing scope for lower Tasmanian spot prices generally and electricity prices are forecast to decline in real terms.

Gas Price Outlook

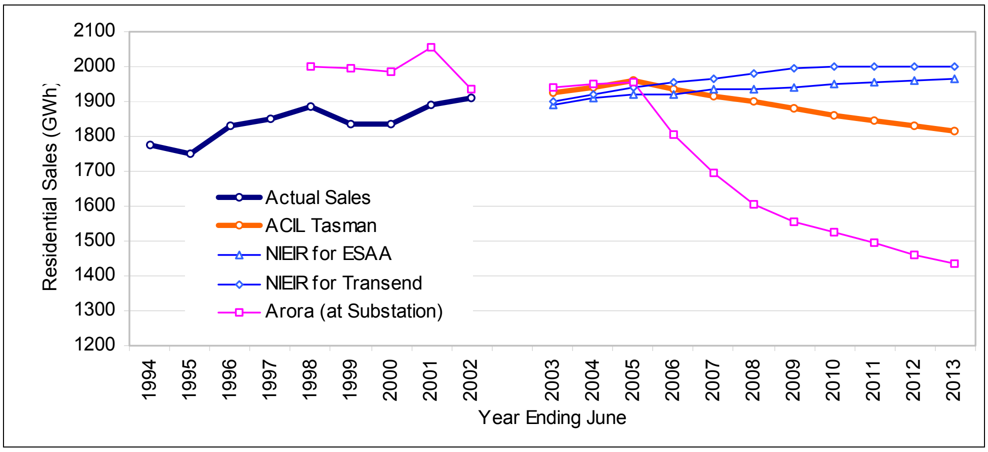
The price of gas in Tasmania will follow similar trends to gas prices in Victoria. Field prices are forecast to escalate with CPI each January while pipeline tariffs are forecast to increase at 80% of CPI.

3.3 Electricity Sales Forecast for Tasmania

3.3.1 Residential Sector

The domestic energy forecast is based on a continuation of the trends in consumption per household for light and power and off peak tariff types but an erosion of the heating tariffs assuming 60% of heating appliance replacements are replaced by gas appliances from 2005 onwards. This results in a forecast average reduction in electricity used per household for space and water heating beyond 2005 of around 4.0% p.a. compared with growth of 2.1% p.a. in the period since 1994. The resultant AT forecast is for a decline beyond 2005 as shown in Figure 3-4**.**

Figure 3-4 Forecast of Residential Electricity Consumption

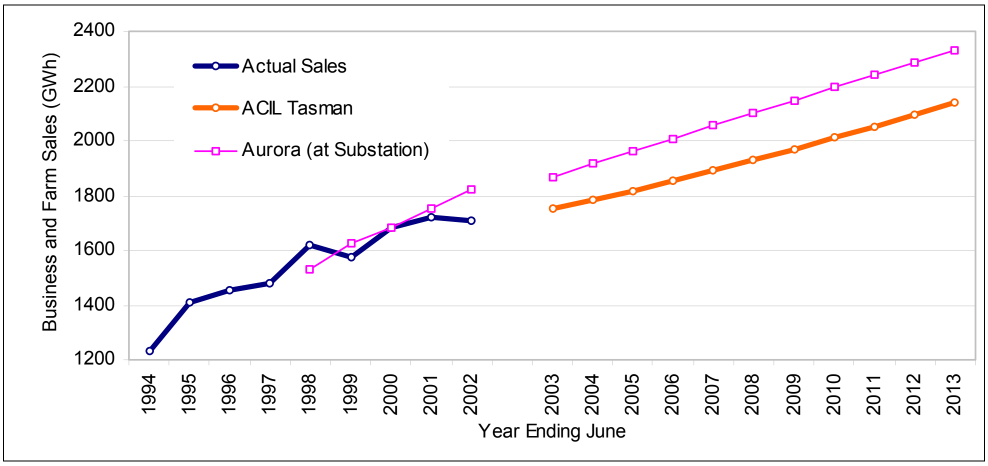


Data source: Actuals from Aurora Annual Reports and Substation Forecast Report

3.3.2 Other Tariff Customers (small business and farm)

The AT forecast of electricity sales to small business and farms in Tasmania is shown in Figure 3-5. The forecast is for growth in sales of 2.1%pa, which incorporates an allowance for loss of heating loads to gas.

Figure 3-5 Forecast of Electricity Sales to Other Tariff Customers (GWh)

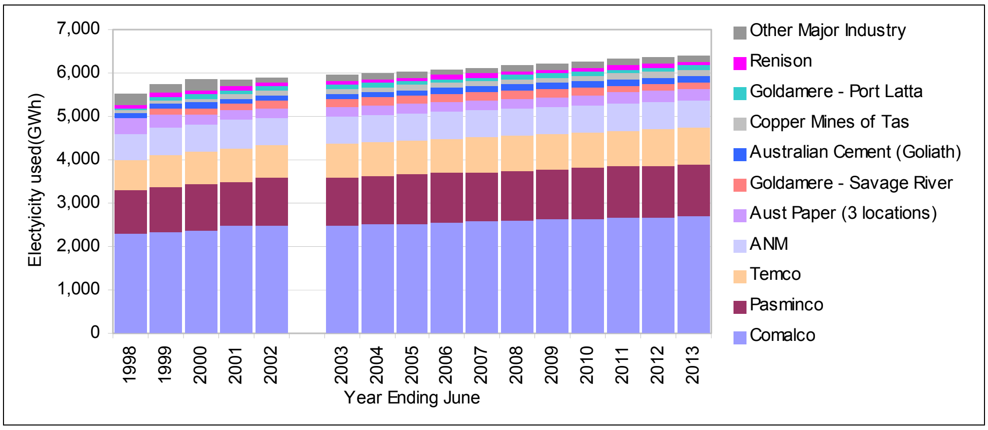


Data source: Actuals from Aurora Annual Reports and Substation Forecast Report

3.3.3 Major Industrial Customers

Electricity use by the 16 major industrial users in 2001/02 was 62% of Tasmania's total electricity sales. The AT forecast of overall electricity sales to major industrial customer to increase at around 0.75% per annum as shown in Figure 3-6.

Figure 3-6 Forecast of Electricity Sales to Major Industrial Customers



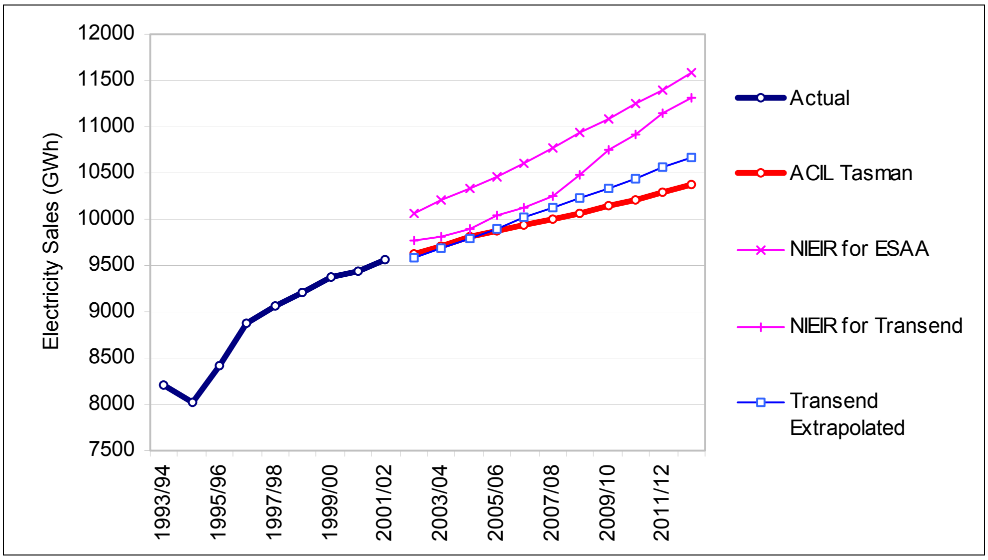
Data source: Past data from Aurora Substation Forecast Report and forecast by ACIL Tasman

3.3.4 Overall Electricity Sales Forecast for Tasmania

The overall AT forecast growth in electricity sales of 0.7% per annum is somewhat less than the average 1.9% per annum recorded over the past decade. This is due mainly to the influence of the introduction of natural gas, particularly on electricity used in space and water heating, and the fact that no new major industrial loads are included in the forecast.

The comparison of the various forecasts of overall electricity sales is shown in Figure 3-7.

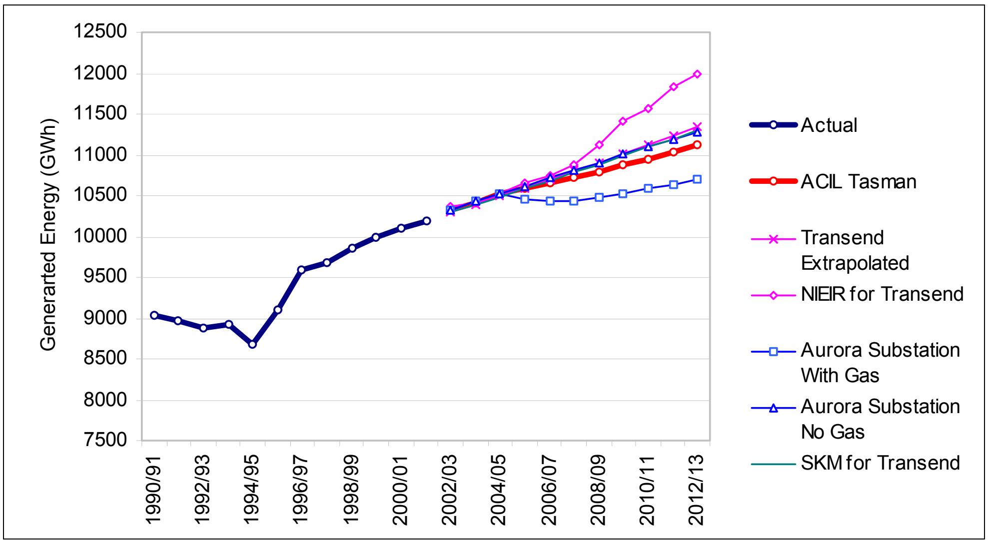
Figure 3-7 ACIL Tasman Forecast of Electricity Sales Compared with Others



3.3.5 Forecast of Generated Energy

Forecasts by AT and others of generated energy are presented in Figure 3-8**.** As can be seen from three forecasts, the Transend Extrapolated, the Aurora Substation without gas and the SKM for Transend are very similar, all have growth close to 1.0%. The AT forecast lies below these forecasts but above the Aurora substation with gas.

Figure 3-8 Forecasts of Generated Energy in Tasmania

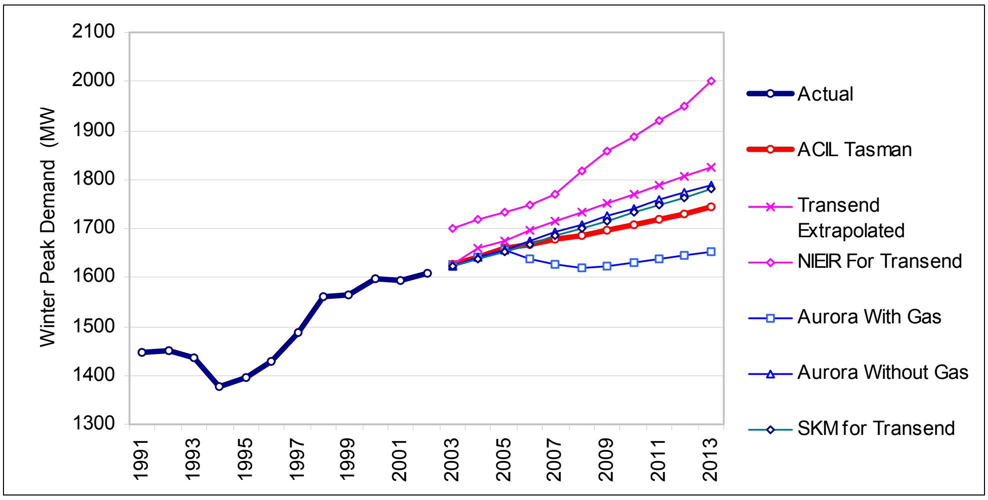


3.4 Forecast of Generated Peak Demand

AT has forecast a gradual increase in load factor meaning a slightly lower growth in winter peak demand than in annual energy.

The AT winter peak demand forecast growth averages 0.74% per annum and is compared with other forecasts in Figure 3-9. Again the AT forecast is lower than Transend extrapolated, SKM and Aurora without gas but higher than Aurora with gas.

Figure 3-9 Forecast of Generated Winter Peak Demand (without Basslink) (MW)



3.5 Energy and Peak Demand with Basslink

Modelling by AT shows that flows on Basslink will be northerly from Tasmania to Victoria during week day peak periods but in the opposite direction in the off-peak and weekends. This means that at the time of the winter peak in Tasmania the flow on Basslink will be in a northerly direction at close to the link's long term rating of 500MW that adds to the peak loading on both the Tasmanian transmission system and generators.

The modelling also shows that in most years more energy flows from Victoria to Tasmania that from Tasmania to Victoria thereby reducing stress on the water storages in Tasmania.

3.6 Regional and Substation Forecasts

3.6.1 Regional Energy Forecast

Using the same twelve regions as in the Aurora Substation Forecast, The AT 12 region forecast is shown in . The growth in East Coast and South East regions is substantially higher in the Aurora forecast.

Table 3-1 Forecast of Energy by Twelve Regions (GWh at substations)

Region	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Historic Grow th 1998/99 to 2001/02	AT Forecast Grow th 2002/03 to 2012/13	Aurora Forecast Grow th (Without Gas)
Central North	1139	1156	1167	1177	1180	1184	1187	1192	1197	1202	1207	1213	-1.6%	0.6%	0.0%
Derw ent Clyde	813	820	825	831	834	838	842	846	850	854	859	863	1.1%	0.5%	1.2%
East Coast	66	69	71	73	74	75	77	79	80	82	84	86	5.1%	2.3%	5.3%
Highlands	57	57	58	58	58	58	58	59	59	59	59	59	0.9%	0.4%	0.3%
Hobart Urban	2237	2268	2289	2309	2317	2326	2335	2346	2357	2368	2380	2393	1.7%	0.6%	0.7%
Midlands North	56	58	59	60	61	61	62	63	63	64	65	66	2.4%	1.5%	1.9%
North East	98	100	101	101	101	101	101	101	101	101	101	101	0.3%	0.3%	1.5%
North West	200	203	205	208	209	210	211	213	215	216	218	220	15.0%	0.9%	0.5%
South East	97	100	102	104	105	106	107	108	110	111	112	114	2.8%	1.5%	3.5%
Southern	238	246	252	258	262	266	271	275	280	285	290	295	3.1%	2.0%	3.5%
Tamar	4190	4239	4280	4323	4356	4390	4425	4461	4498	4535	4573	4612	2.2%	0.9%	0.9%
West Coast	516	521	525	529	533	537	541	544	548	552	556	560	4.3%	0.7%	0.2%
Total Tasmania	9707	9836	9933	10030	10091	10153	10218	10286	10357	10430	10506	10583	1.8%	0.79%	0.89%

3.6.2 Substation Coincident Demand at Winter Peak (MW)

The regional energies have been allocated to the 52 substations then load and coincidence factors applied to forecast the substation contribution the Tasmanian winter peak demand. This is presented in **Appendix C.**

3.7 Generation

Tasmania currently has a total of 2513 MW of capacity installed comprising 28 hydro stations with a capacity of 2263MW , the Woolnorth wind farm with a capacity of 10MW and the gas/oil fired Bell Bay power station with a capacity of 240MW.

3.7.1 Forecast of Generation Capacity

The plant capacity is forecast to include the committed and advanced projects identified in the 2002 Planning Report. A forecast of total installed plant capacity in Tasmania at each major injection point, after adding in these developments, is shown in Table 3-2**.**

Table 3-2 Forecast of Installed Plant Capacity at Major Injection Points (MW)

Major Injection Point	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Farrell	626	626	626	626	626	626	626	626	626	626	626
Sheffield	319	373	373	373	373	373	373	373	373	373	373
Palmerston	302	302	302	302	347	347	347	347	347	347	347
Derw ent 110kV	300	302	302	302	302	302	302	302	302	302	302
Derw ent 240kV	215	215	215	215	215	215	215	215	215	215	215
Trevallyn	80	80	80	96	96	96	96	96	96	96	96
Gordon	432	432	432	432	432	432	432	432	432	432	432
George Tow n	240	240	240	240	240	240	240	240	240	240	240
Southw ood	0	0	0	30	30	30	30	30	30	30	30
TEST	0	0	15	15	15	15	15	15	15	15	15
Total Tasmania	2513	2570	2584	2630	2675	2675	2675	2675	2675	2675	2675

3.7.2 Winter Peak Loading on Tasmanian Generators

The forecast generation at each major injection point to meet the forecast peak generated demand in Tasmania including Basslink is shown in Table 3-3. It has been assumed that the wind generators would not contribute to the system winter peak.

Table 3-3 Generation at Major Injection Points during the Winter Peak (MW)

Major Injection Point	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Farrell	626	626	626	626	626	626	626	626	626	626	626
Sheffield	319	373	373	373	373	373	373	373	373	373	373
Palmerston	302	302	302	302	347	347	347	347	347	347	347
Derw ent 110kV	300	302	302	302	302	302	302	302	302	302	302
Derw ent 240kV	215	215	215	215	215	215	215	215	215	215	215
Trevallyn	80	80	80	96	96	96	96	96	96	96	96
Gordon	432	432	432	432	432	432	432	432	432	432	432
George Tow n	240	240	240	240	240	240	240	240	240	240	240
Southw ood	0	0	0	30	30	30	30	30	30	30	30
TEST	0	0	15	15	15	15	15	15	15	15	15
Total Tasmania	2513	2570	2584	2630	2675	2675	2675	2675	2675	2675	2675

3.8 Forecast Findings and Conclusions

The AT forecast is for growth in annual electricity requirements of 0.7% per annum which is lower than the growth of 1.9% per annum recorded over the past decade. This is mainly because the minor stimulatory effects on the economy from the introduction of natural gas are more than offset by the loss of space and water heating loads to gas in the residential and small businesses sectors. AT also forecasts an increase in winter peak demand of 0.8% per annum.

Compared with other forecasts, the AT forecast of energy growth is slightly less than the SKM and Aurora (without gas) forecast growth of 0.9% per annum and the Transend extrapolated growth of 1.0% per annum. However it is substantially less than the NIEIR econometric forecast with average growth of 1.5% per annum. The Aurora forecast with gas has an average annual growth rate of only 0.4% per annum, substantially lower than the AT forecast.

There is however variation in the regional and substation forecasts between AT and Aurora without gas. The AT forecast has higher growth generally in the north and west than the Aurora (without gas) forecast and generally noticeably lower growth in the east and south regions of the State. These differences in the regional load forecast have potential to reduce the capital investment plans of Transend in some regions and increase it in others, although generally a minor number of megawatts is involved.

Aurora chose to use the forecast, without gas, for substation and distribution planning purposes apparently because the possible reduction in load due to the introduction of natural gas was seen as too uncertain to be used as the basis. Even so the AT forecast which incorporates an allowance for the introduction of gas, and the SKM forecast, are only marginally lower than the Aurora forecast without gas. In view of this it would seem that use of the Aurora without gas forecast is reasonable.

The pattern of generation at peak times is forecast by AT to continue to be dependent on storage conditions and rainfall pattern at least until interconnection with Victoria. Basslink is projected to contribute some 500MW to the Tasmanian peak load and it has been assumed that this peak will be met by the Tasmanian hydro stations. Existing and planned wind farms in Tasmania have not been included as contributing to meeting the peak demand as there is no guarantee that they will be operating. Given this uncertainty we assume that SKM would have studied a number of generation patterns in its load flow modelling for Transend to ensure that there was adequate capacity on the transmission system to handle any pattern of generation.

Basslink is expected to marginally reduce the energy required from Tasmania's hydro stations but is expected to cause a more intensive usage of this plant at peak times. Wind farms will also reduce the need for energy production by the Tasmanian hydro plants but the contribution of wind farms to the winter peak is uncertain, depending as it does on prevailing wind conditions. Ideally from a market perspective the transmission system should have the capacity to allow any pattern of generation which is available at the time.

4. Benchmarking

4.1 Basis for Benchmarking Review

The benchmarking component of this review considers two different approaches:

- Benchmarking of output costs or performance, using a range of measures such as Opex per MW capacity, or Opex per network km. These output measures suffer from difficulty in reasonable comparisons on any individual benchmark, as all businesses have their own “unique” operating environment. Usually some measures can be found to demonstrate lowest cost or best performance for any chosen service provider. Various output benchmarking studies have been utilised by Transend in support of its position. This section will review the output benchmarks.
- Benchmarking of asset management inputs and processes. This is a process applied successfully to many infrastructure businesses, and has the advantage that it can be applied appropriately to any business operating circumstances, however no financial assessment is included. This process benchmarking approach has been applied under the asset management component of this review in Section 5, and has revealed significant deficiencies in the commercial and business processes applied to Transend’s Revenue Cap forecasts.

4.2 Output Benchmarking

4.2.1 Difficulties in Output Benchmarking

Benchmark Economics (Application, Appendix 2) identified the difficulties associated with attempting to benchmark Transend against other TNSPs operating in a dissimilar environment such as its reliance on Hydro, extensive network of transmission lines due to the size and location of the sub-stations to the population. The analysis undertaken by Benchmark Economics, concluded that Transend is a relatively low cost operator (based on available 2002 figures), but state that the reason for this assessment is “unclear – although the relatively poor service performance is potentially one consequence of such low operating costs” (Application, Appendix 1, page 32 of Benchmark Economics Report).

However while benchmarking is a popular method to measure a business entity’s performance, potentially this process can easily distort perception. For example, there is a distortion in Transend’s operating environment whereby up to 60% of all electricity consumed in Tasmania is used by 5 or 6 Companies at a very high load factor, showing a very high utilisation of assets specifically needed for these companies.

This potentially misrepresents the utilisation averages used by Transend/Benchmark Economics in their analyses. Conversely, Benchmark Economics puts the case for considering capacity-related benchmarks instead of peak demand benchmarks, due to the high capacity to peak ratio.

Other factors of relevance in TNSP benchmarking analysis of Transend include:

- 99% of the power Transend transmits is from dispersed, relatively small hydro generators
- The transmission network has a wide geographic spread serving a relatively small population.
- Transend operates at down to lower voltages than other TNSPs

These factors have varying impacts on comparative indicators.

So how is it possible to make cohesive and meaningful benchmarks? GHD believes this is difficult and subject to misinterpretation. Tasmania has been endowed with natural waterways that enable cost effective hydro systems to be built. Linking these diverse sources of energy are transmission systems that are incrementally developed and until there is a significant change in technology the cost of transmission may be largely a function of the system rather than its management. GHD believes that it is more important to structure performance measures around the quality of management inputs and processes rather than depending on industry performance or output benchmarking that may deliver unreliable results due to the difficulty in normalising for variations in asset portfolio characteristics, operating conditions and the business environment.

4.2.2 Consideration of Output Benchmarks

With respect to output benchmarking, in considering a range of reports and benchmark Opex-based measures, Transend appeared as a lower to middle cost TNSP when compared nationally, based on either 1999/2000 or 2001/2002 revenue figures. The conclusions of these benchmarking studies change significantly if benchmarks are reviewed using Transend’s Application forecasts over the RP. Transend’s position, using a range of Opex benchmark measures, shows an increasing trend compared to other TNSPs for the period to 2005-06, stabilising in later years as one of the higher cost TNSPs. This comparison does not provide for scale or other effects mentioned above. No comparison has been made on total revenue, due to the difficulty in normalising for individual differences in TNSPs. Comparison of Transend’s Application Opex revenues against other TNSPs for a range of Opex benchmarks are shown in Figures 4-1 to 4-5, indicating the increasing trend referred to above. These Figures, were provided by Transend, using data provided by the Commission for other TNSP’s.

Figure 4-1 Opex/Assets (percentage), 2001-02 to 2008-09

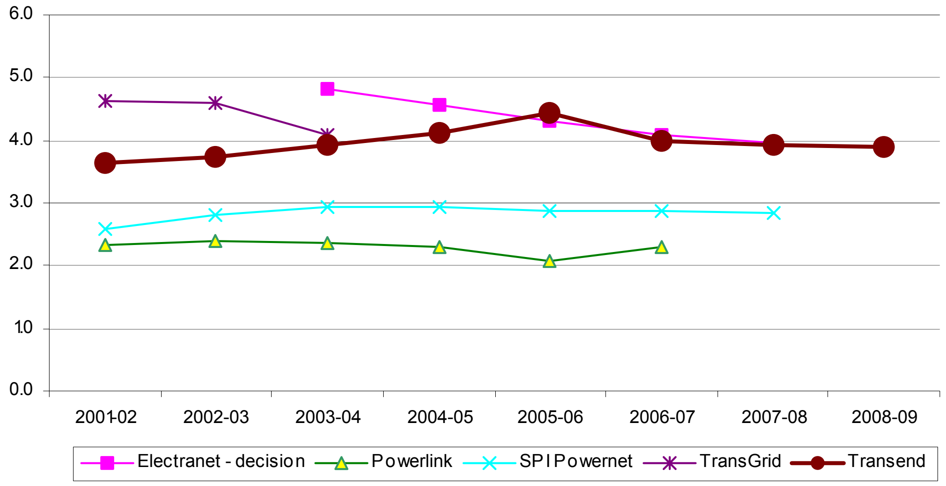


Figure 4-2 Opex/Line Length ($'000 per route kilometre), 2001-02 to 2008-09

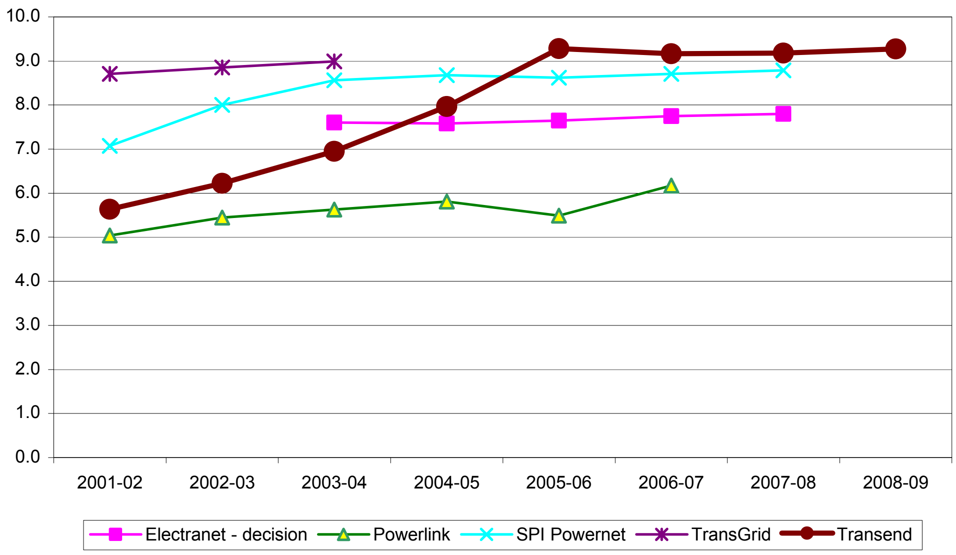


Figure 4-3 Opex/Capacity ($'000/MW), 2001-02 to 2008-09

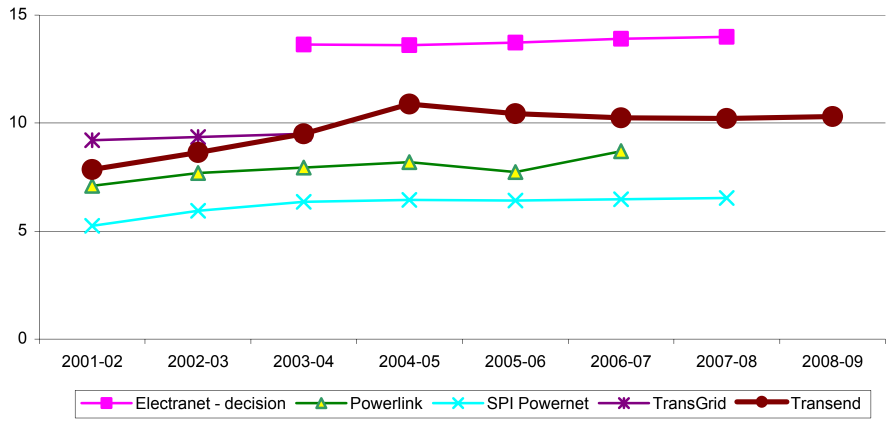


Figure 4-4 Opex/Peak Demand ($'000/MW), 2001-02 to 2008-09

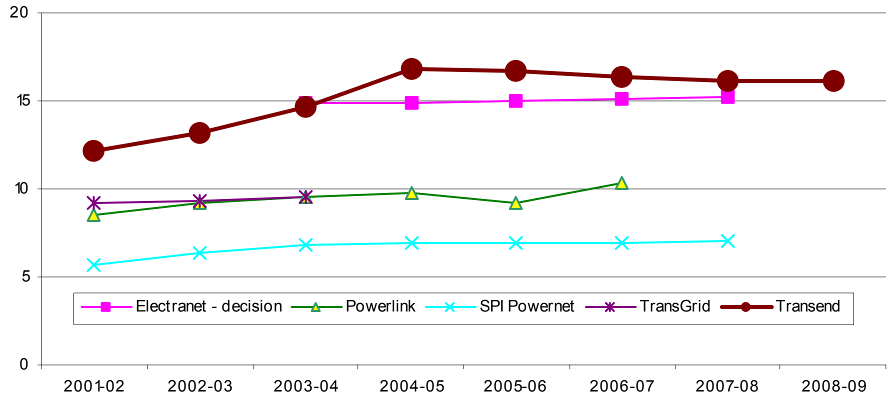
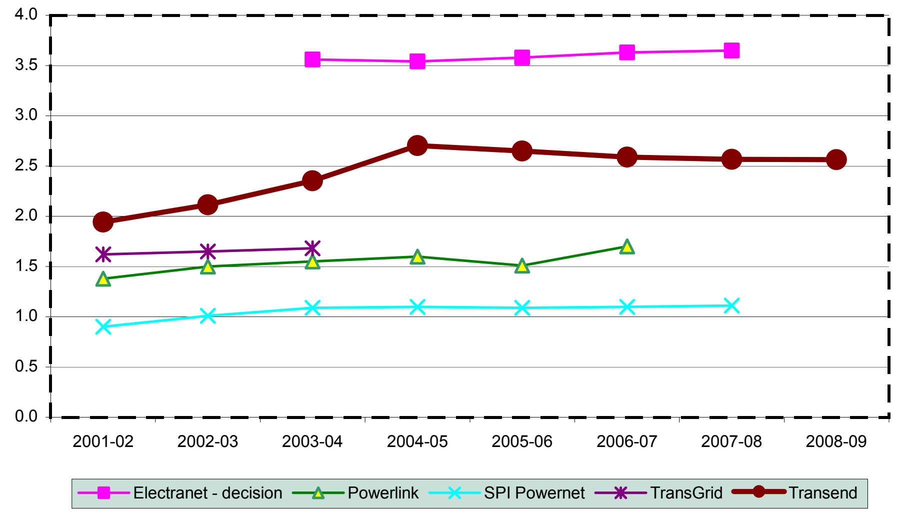


Figure 4-5 Opex/GWh, 2001-02 to 2008-09



4.3 Summary of Findings

The overall assessment is that Transend is currently a lower to middle cost Transmission Network Service Provider (TNSP), with below average performance and significant shortfalls in terms of efficient investment decision-making capability. This indicates a need for Transend to focus on value outcomes by applying a higher level of rigour to risk assessment and cost/risk/service level tradeoffs in investment.

With respect to output benchmarking, in considering a range of reports and benchmark Opex-based measures, Transend appeared as a lower to middle cost TNSP when compared nationally, based on either 1999/2000 or 2001/2002 revenue figures. The conclusions of these benchmarking studies change significantly if benchmarks are reviewed using Transend's Application forecasts over the RP. Transend's position, using a range of Opex benchmark measures, shows an increasing trend compared to other TNSPs for the period to 2005-06, then stabilising in later years as one of the highest cost TNSPs. No comparison has been made on total revenue, due to the difficulty in normalising for individual differences in TNSPs.

5. Asset Management

5.1 Basis of Asset Management Review

This section has reviewed asset management in the widest sense. Utility businesses have large infrastructure asset bases relative to other businesses, and hence asset-related expenditure dominates total corporate expenditure. The asset management review has thus considered all asset management activities by Transend from inputs (business drivers, asset base) to outputs (expenditure forecasts and strategies), and considered them against a “best appropriate practice” considered by GHD to be suitable for a TNSP.

Asset management activities of relevance include:

- Organisational issues
- Processes and practices
- Asset Management Plan documentation
- Data and knowledge
- Asset management information systems
- People issues
- Commercial tactics

This approach is extensively used by GHD to undertake asset management and expenditure reviews, and is an extension of the approach detailed in the International Infrastructure Management Manual 2001, which was endorsed by the relevant Ministers of the Australian and New Zealand governments as appropriate for use by infrastructure businesses.

The review has been undertaken at a reasonably high level, and has considered other reports provided to GHD to support the findings.

5.2 Organisation Issues

Transend appears to have an appropriate structure to effectively manage its business under the “asset manager / service provider” model, which is common in private utility businesses and separates the asset manager from the service provider through a performance agreement. Transend is further developing this model to provide for future changes to its operations on NEM entry.

Transend has much of its activity outsourced, including all field services (including field operations, maintenance and fault response, and construction), many engineering and specialist services (including protection and test services, design and system modelling), consulting and telecommunications services. This structure would normally be considered efficient by its nature.

However, Transend is somewhat constrained by the relative geographic isolation of Tasmania, and relies for many of its services on other electricity service providers which were part of the now disaggregated HEC, namely Aurora, Hydro Tasmania, Hydro Consulting, Hydro Telecommunications Services and Hydro Protection and Test Services. Consequently, issues such as having an adequate source of skilled resources and sufficient contractors to provide a competitive marketplace become more important and must be given careful consideration when making asset management decisions.

All major construction is competitively tendered using the design and construct mechanism, which is appropriate. Most of these contractors are based on the mainland.

Outsourced activities are reviewed to ensure there is appropriate levels of control of service providers. This approach is considered appropriate on the basis of improved effectiveness and cost efficiency.

GHD considers that the organisation structure is appropriate for a major utility business operating in a regulated environment.

5.3 Overall Asset Management Processes and Practices

Transend's asset management (AM) process is outlined in Transend's key AM document, the Transmission System Management Plan (TSMP). The overall AM process (from Appendix 1 of the TSMP) follows a logical progression, including the following aspects:

- Understanding requirements of customers, relevant legislation, Codes and Australian Standards, and practice guidelines.
- Understanding market and regulatory drivers including licence, connection agreements and using input from the Annual Planning Review process for load growth and reliability.
- Providing input from the above to asset creation and in-service asset management processes.
- Project development and approvals
- Asset enhancement to meet Code, legislative, safety or environmental compliance, or address design deficiencies
- Replacement or refurbishment due to deficiencies in system performance, asset performance, or obsolescence.
- Maintenance based on condition assessments and testing, customer requirements, performance monitoring and manufacturers' recommendations.
- Outage and transmission operations management
- Project/contract management for Capex and maintenance
- Performance monitoring and review processes

Transend was requested to provide information on the process by which the projects or programs identified under the above process were rolled up to a corporate level, considered against overall business drivers and customer requirements, prioritised and rationalised, reviewed for revenue and price impacts and constraints, and trade-offs made to arrive at an acceptable overall expenditure forecast. While this process was described in part and was undertaken as part of an expenditure review, it appeared to be lacking in some key aspects:

- The process for consideration of total revenue implications or price impacts appeared to be ad-hoc and did not involve any effective customer consultation or modelling on which to base budget rationalisation activities.
- Limited evidence was provided of risk/cost/service level trade-offs at a corporate level as a means of budget rationalisations or decisions based on residual risk assessment. Best appropriate practice in this respect include failure mode analysis, for example.

This review suggests that Transend has carefully considered the technical processes and interactions that apply within the organisation, but has not adequately addressed the commercial aspects that are also critical to deriving expenditure forecasts within a regulated environment.

5.4 Asset Management Plan Documentation

Transend's key AM document is the Transmission System Management Plan (TSMP), produced in late March 2003, which is the latest version of Transend's Asset Management Plan. This document superseded Transend's previous Asset Management Plan and provides confidential appendices which detail the costs associated with the programs and projects outlines in the main document. The TSMP applies to the planning period from June 2003 to June 2009, hence covering the RP.

Other key AM documents that are a requirement of Transend's Licence include:

- Vegetation Management Plan
- Service Plan (incorporating Service Standards)
- Compliance Plan

The TSMP includes management of both transmission network and connection assets with respect to:

- Asset creation and augmentation
- Renewal, refurbishment and upgrading, and
- Operations and maintenance

The TSMP refers to a range of major supporting documents (referred to as the Development Plan; Maintenance, Refurbishment, Replacement, and Enhancement Plan; and Non-network Plans). These documents do not exist as titles, but are a collection of subsidiary documents underlying the TSMP. The main information exists in the TSMP and Appendices.

Underlying the TSMP are individual project reports or specific asset related documents that were prepared either by Transend or its predecessor body, the HEC. Some of these documents date from 1993 (eg. some circuit breaker plans). A significant number of documents have recently been produced, such as the Easement Management Plan (April 2003) and Asset Management Plans (AMPs) for Transmission Line Foundations, Conductor Assemblies, Support Assemblies and Insulator String Assemblies (all dated March 2003, Issue 0.1).

GHD concludes that Transend's AM documentation is in a rapid state of development. Numerous documents have been prepared, especially over the last few months. These documents are based on best practice and compare with other TNSP's. Many documents are still to be developed, reviewed and updated, or coordinated under the TSMP. Many of the programs or practices referred to in the documentation are yet to be implemented.

5.5 Processes and Practices

Review of some of the above documents indicates that Transend has developed many appropriate approaches to asset inspection, condition assessment and testing, refurbishment and replacement but also needs to address many issues, including:

- Transmission line criticality has not been reviewed since 1995.
- Replacement programs for many assets are still based on life expectancy and/or current knowledge of assets. A monitoring, inspection and testing regime is established for the RP to increase the level of condition assessments as a basis for maintenance and renewals (eg. climbing inspections are proposed for transmission towers. In the interim, an estimate based on initial inspections has been included in the expenditure forecast).
- Condition rating processes for some assets are still to be developed (eg. insulator strings).
- Techniques for non-destructive testing (NDT) of some assets to be assessed and adopted (eg. for transmission tower foundations, steel poles, or conductor joint condition).
- A number of studies are identified as needed to investigate cost effective rehabilitation techniques for assets (eg micro pile foundations for transmission towers).

The above review indicates that, while Transend has progressed significantly with AM documentation, improvement is still required in many areas of documentation to bring the organisation to an appropriate practice level, commensurate with the benefits in terms of effectiveness and efficiency that this is expected to bring.

5.6 Information Systems, Data and Knowledge

The major information systems in use by Transend are described in the TSMP, and include:

- Works Asset Scheduling and Programming (WASP) system for works management and some other asset management functions. The system has the capability to provide a full suite of integrated asset management functions.
- Plant Request Outage Management System (PROMS), used to coordinate and manage system outages.
- Operational information system for system controllers, operators, customers, Code participants and generators.
- Geographic Information System (GIS) which is being implemented to link network asset information with landowner information.
- Numerous spreadsheet-based systems for recording and maintaining information on asset attributes, condition and historical costs.

Transend has adopted a proposal to upgrade the WASP system to an integrated Asset Management Information System (AMIS) through a staged process. In general, GHD supports this concept, as information is held by Transend in many forms and its use is not integrated. The application of decision support systems has yet to be developed to an appropriate level. The absence of decision support systems was particularly noted, such as failure mode prediction models, risk assessment tools, options development and evaluation tools, and optimised renewal decision-making (ORDM) tools. Further comment is made on the AMIS proposal in the Non-network Capex review.

Data and knowledge of assets is critical to enable effective and efficient decision making on maintenance and renewals. Transend has reasonably comprehensive data sets for most assets, with asset technical data between 80% and 100% complete, and condition assessments between 30% and 100% complete. The main deficiencies in condition data occur in transmission supports and conductor assemblies, and some substation asset groups. Cost data is also comprehensive.

GHD considers that this level of data and knowledge of assets is not fully adequate as a basis for determining renewals and maintenance requirements. Areas of shortfall occur in further decision-making data and knowledge, including failure consequence data and performance information (eg. reliability) which would support the IT systems identified above.

These areas are important ‘best appropriate practice’ processes which should be addressed by Transend.

5.7 People Issues

Transend has grown significantly in staff numbers to its present level of 120, with projected further growth to around 140 people. Core functions have been strengthened internally and GHD finds that Transend has a reasonably strong level of technical expertise within the business.

With respect to organisational culture, GHD's general impression was of a strong technical and service culture, but with a low emphasis on cost efficiencies and the need to consider cost impacts in all decisions.

5.8 Review Findings

The following summary findings relate to Transend's overall asset management practices:

- Transend is structured appropriately under the 'asset manager / service provider' model, and is further developing this model to provide for future changes to its operations on NEM entry.
- Transend has carefully considered the technical processes and interactions that apply within the organisation, but has not adequately addressed the commercial aspects that are also critical to deriving expenditure forecasts within a regulated environment. In particular, budget rationalisation processes incorporating risk-based cost and service level trade-offs, and decisions utilising residual risk assessment, are not well developed. Budget rationalisation currently appears to be based on a discussion process of what is reasonable and achievable. Risk assessments are at a high level in terms of business risk and not adequately integrated into investment decision processes.
- The organisation appears to have a strong technical and service culture, but with a low emphasis on cost efficiencies and the need to consider cost impacts in all decisions.
- Transend's AM documentation is in a rapid state of development. Numerous documents have been prepared and many documents are still to be developed, reviewed and updated, or coordinated under the TSMP. Many of the programs or practices referred to in the documentation are yet to be implemented.
- The need for a significantly improved Asset Management Information System is acknowledged. The absence of decision support systems was particularly noted which impedes achievement of best practice economic asset management decision-making.
- Transend has reasonably comprehensive asset technical, condition and cost data sets for most assets, however areas of shortfall occur in further decision-making data and knowledge, including failure consequence data and performance information (eg. reliability) which would support the IT systems identified above.

6. Capital Expenditure

6.1 Basis for Review

This Review is based on assessment of information provided by Transend, including:

- Historical Capex information,
- Category break up of Capex amounts shown in the Application,
- Overall plans and programs for Capex,
- Individual sampled project reports and summaries,
- Support information, and
- Transend responses to enquiries arising during the Review.

6.2 Regulated and Non-regulated Expenditure

Transend's capital expenditure is currently subject to the Tasmania Electricity Code (TEC) and will be subject to the National Electricity Code (NEC) once Tasmania enters the National Electricity Market (NEM) in 2005.

Under Transend's current regulation the local jurisdiction (OTTER) makes a declaration as to which services are regulated. Under the current revenue determination all transmission services were 'declared' and as such are 'regulated' assets. Transend has indicated that it expects all assets commissioned and generally in service as at 31 December 2003 will continue to be considered 'regulated' assets and as such this is the basis of its Application.

6.3 Historical Expenditure

As the transmission assets were operated and maintained as part of the HEC prior to its disaggregation in 1998, pre-1998 expenditure on transmission assets alone was advised by Transend as difficult to obtain. Transend's Capital Expenditure over the period since 1998 is summarised in Table 6-1**.**

Table 6-1 Historical Capital Expenditure (actual $ million)

Financial Year	Renewal Capex	Development Capex	Non-network Capex	Total Capex
1998/99	15.7	37.8	0.5	**54.0**
1999/00	25.6	9.5	0.9	**36.0**
2000/01	13.8	15.2	1.3	**30.3**
2001/02	16.6	12	2.5	**31.0**
		Total for 4 Years		**151.4**

This is equivalent to approximately $170 million in 2002-03 dollars or an average of $42.5 million per year. The renewal capital expenditure has accounted for nearly half of the total. Transend planned $55m and has projected some $53 million Capex (in service) in 2002-03.

6.4 Overall Capital Expenditure in Revenue Application

The total capital expenditure (on a rolled-in to asset base basis) for the RP is summarised in Table 6-2**.** Amounts shown as 'variable' are for those projects dependent on specific customer-driven developments and considered by Transend to have probabilities of proceeding between 10% and 80%. The variable project costs included in the Table 6.2 below are total budgets. These have been further refined to weighted costs (probability x estimated cost) by Transend and this aspect is further considered in Section 6.7.

Table 6-2 Revenue Cap Application Capital Expenditure Summary (2002/03 $m)

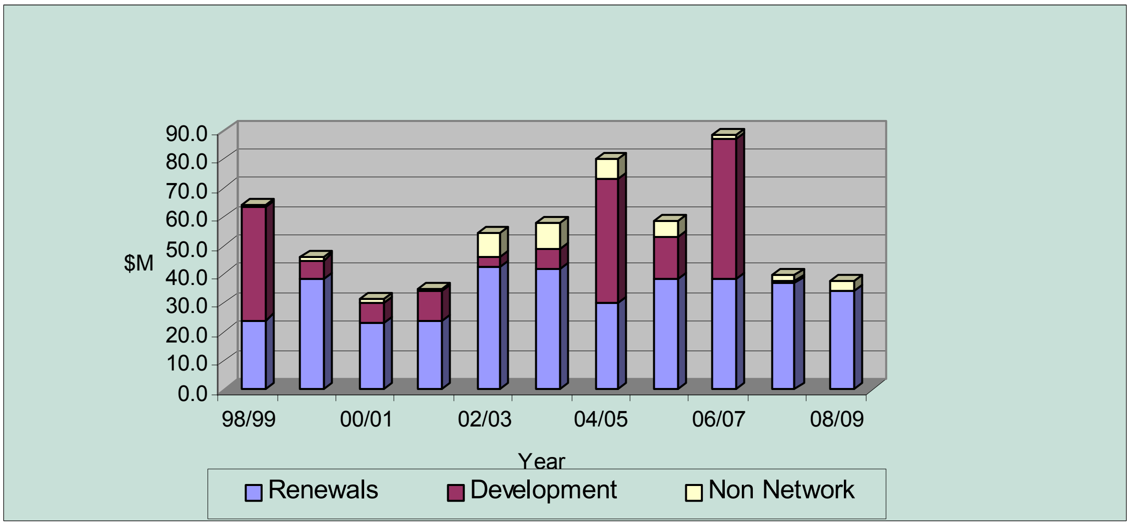
	Jan to Jun 2004	2004-05	2005-06	2006-07	2007-08	2008-09	Total
Development fixed projects	2.8	43.2	14.3	48.3	0.6	0	109.2
Refurbishment	7.4	6.8	8.7	8.1	4.9	2.1	38.1
Replacement	9.5	23	29.9	30.5	32	31.8	156.8
Non network	7	6.9	5.5	1.5	2.3	3.5	26.7
Total with fixed projects	26.8	80	58.4	88.4	39.8	37.5	330.8
Variable	0	28	10.5	16.9	24.7	69.6	149.6
Total	**26.8**	**108**	**68.9**	**105.3**	**64.5**	**107.1**	**480.4**

The forecast capital expenditure for the RP is approximately $60 million per year (in 2002-03 dollars) with the capital expenditure on renewals/refurbishment accounting for 59% of the total. This average amount does not include any allowance for development projects that are termed 'variable' by Transend in the Application (i.e. projects with the likelihood of occurrence of less than 100%).

A comparison of Capex in the Application with historical expenditure is provided in Figure 6-1**.**

Figure 6-1 Historical and Application Fixed Capex In Service (2002/03 $m)

Note: Conversion of actual historical $ to 2002/03 $ results in differences between this Figure and Table 6.1.



The above figure indicates:

- Wide variations in total Capex have occurred and are expected to occur,
- Development Capex is most volatile,
- Renewals expenditure is proposed to progress at a higher level than historically, with a significant reduction in renewals in 2000/01 and 2001/02 being reversed in subsequent years.

Each separate category of expenditure is considered in more detail below.

6.5 Strategic Issues

Transend's business objectives are summarised in Table 6-3**.**

Table 6-3 Transend Business Objectives

Criterion	**Objective**	**Target**
Safety	Ensure a safe working environment for employees, contractors and the public	Compliance with industry safety codes and relevant legislation
Supply Reliability	Provide a reliable supply of electricity to Transend's demand-side connection customers	Less than 20 minutes lost per annum
Supply Security	Maintain the power system in a secure operating state as defined in the Tasmanian Electricity Code (TEC)	100% compliance with TEC
Costs	Minimise costs of operating the business	Meet operating budget
Return on Capital	Achieve appropriate and sustainable return on capital employed in the business	Achieve budget return on owners' equity

For capital investment, a business will have different Capex evaluation processes for the different investment categories due to different business drivers. These categories are typically:

- Renewal investment
- Growth investment
- Improvements in levels of service
- Business efficiency improvements
- Regulatory compliance

Some of the key areas for a business and how Transend's capital expenditure processes relate to them are discussed below.

6.5.1 Safety and OH&S

Businesses have a responsibility and statutory obligations to provide for public safety and a safe workplace for their employees. Consequently, safety capital expenditure may not be justified under normal economic return criteria. For this type of investment, GHD would expect to see justification in the form of risk assessment carried out as part of business case evaluation, which considers the probability and consequences of injury to the public and/or staff.

Transend has to follow State and Federal legislation and Codes in relation to safety and OH&S. Transend has reported for 2001-02 that it has achieved its goal of zero workplace accidents and this is the third consecutive year it has done so.

GHD has seen evidence that Transend considers safety and OH&S issues in its business risk assessment of capital projects.

It is noted that Transend has in place processes for continued analysis of human errors and the operating environment that leads to reviews of system and design deficiencies. Some non-network capital expenditure in the Application has been identified for improvement of asset recording systems to assist this process.

6.5.2 Reliability

Consumers require a level of reliability commensurate with their use of the system and what they are willing to pay for the service. The business providing the service needs to understand the levels required and then reasonably predict equipment failure rates in terms of reliability and life mortality. The timing of capital expenditure depends on the ability to accurately predict both the failure mode of the asset and the timing of the elements involved in the failure. The prediction of reliability relates to the ability to track unplanned maintenance or faults, and outages, and thus predict the trend of future likely failures.

A key element of renewal justification involves the issue of end of life failure for assets that have no failure history, yet their condition is getting to the point that they may suffer catastrophic failure.

Prior to Transend's formation, HEC undertook a major assessment of the transmission network and put in place a renewal program for those assets that had replacement drivers, such as reliability. Transend continued the program and ongoing assessment when it was formed.

Transend in its Application has based its renewal capital expenditure on reliability as one of the key drivers, of which a key element is service standards. To this end Transend has as part of its connection point agreements with customers, performance targets and reporting. Transend has also included in the Application past performances for a number of targets relating to availability and loss of supply events.

Transend as part of its continuing asset management process has analysed the performance of its network since Transend was formed in 1998. In broad terms the availability measures for different circuit types is summarised in Table 6-4.

Table 6-4 Historical System Availability

Circuit Type	1998/99	1999/00	2000/01	2001/02	Comment
Transmission lines	99.13%	99.17%	98.96%	99.17%	Has been fairly stable with an average availability of 99.11%. The statistics show that the unavailability due to faults is very small (worst case less than 0.05%). The balance is due to capital and maintenance both planned and unplanned.
Transformer circuits	98.47%	98.7%	99.17%	99.13%	Has been fairly stable with an average availability of 98.87%. The statistics show that the unavailability due to faults is very small (worst case less than 0.03%). The balance is due to capital and maintenance both planned and unplanned.

Transend also considers reactive plant availability, however the plant is relatively young and records are not of a statistically representative size. The average availability has been 99.6%.

Transend has also considered supply reliability through examining the supply interruptions as a result of an outage. It has analysed material and significant loss of supply events, defined as greater than 0.1 system minutes loss of supply and greater than 2 system minutes loss of supply respectively. Since 1998, there were a total of 98 loss of supply events ranging from 0.0003 to 38.4 system minutes, detailed in Table 6-5.

Table 6-5 Historical Supply Reliability Performance

Supply Reliability Indicator	1998/99	1999/00	2000/01	2001/02
Greater than 0.1 system minutes	13	16	15	16
Greater than 2 system minutes	1	4	3	1

Transend also reports to OTTER on system performance against key performance indicators that have been agreed between OTTER and Transend. The Transmission System Performance Report 2001-2002 to OTTER is summarised in Table 6-6.

Table 6-6 Transend System Performance 2001-2002

Performance measure	Result versus Target
Transmission system reliability – unserved energy and system minutes	Both well within target.
Distribution system connection point reliability	The average number of forced outages per connection point per annum and average forced outage duration minutes per connection point per annum were outside (or failed) the targets for both Firm (an alternative supply point is available) and Non-firm (an alternative supply point is not available) connections.
Direct connection point reliability	There are no targets given, however the results are outside the distribution targets.
Generator connection point reliability	The performance in number of forced outages and outage duration were both well within targets.
Transmission network availability	All targets were met
Distribution system connection point unavailability	Firm targets were met. Non-firm target for average planned outage duration was not met.
Generator connection point unavailability	Firm targets were not met and Non-firm were met.
Quality of Supply (QoS)	Two direct connect customers raised QoS concerns. Transend has now initiated a QoS monitoring program.

6.5.3 Environmental

Like safety and OH&S, Capex investment for environmental drivers is driven by legislation and codes. Transend has in place an accredited ISO 14001 Environmental Management System. Some of the compliance projects are continued disposal of PCB contaminated instrument transformers and replacement of temporary oil bunding in substations. Noise from substation transformers is a community concern that Transend is managing by monitoring and responding as required.

6.5.4 Supply Security

Security of the system relates to the ability of the network to maintain supply under loss of system elements. The criteria are normally expressed in terms of N where N is system normal with no allowance for fault or contingency. N-1 means the system is able to meet the peak loads with one credible fault or contingency. TNSPs design and plan their networks to identified security and planning criteria.

The National Electricity Code in Section 4.2.6 General Principles for Maintaining Power System Security states the following:

"The power system security principles are as follows:

(a) To the extent practicable, the power system should be operated such that it is and will remain in a secure operating state.

(b) Following a credible contingency event or a significant change in power system conditions, it is possible that the power system may no longer be in a condition which could be considered secure on the occurrence of a further contingency event. …….

(c) Adequate load shedding facilities initiated automatically by frequency conditions outside the normal operating frequency excursion band should be available and in service to restore the power system to a satisfactory operating state following significant multiple contingency events. "

Transend currently operates under the Tasmania Electricity Code that has the same principles. The regulator is charged with the responsibility to develop system security and planning criteria, but in Tasmania's case, these criteria were not established by OTTER.

Transend engaged SKM to determine a development capital expenditure program for the RP. In carrying out that analysis SKM developed a set of system security and planning criteria.

Transend has produced documentation that indicates that Aurora has, in principle, accepted the security and planning criteria. There did not appear to be evidence that Aurora has been given any indication of the cost to meet the new criteria.

Documentation provided by Transend from Hydro indicates that Hydro agreed with the overall security criteria approach, subject to knowing the impact on Transend's capital program before being signed off. Hydro notes that "..it does seem problematic to 'sign off' on security criteria before we are able to understand the impact on Transend's capital program." Further, Hydro adds that "The rationale for the proposed system criteria would also be strengthened by an overall cost benefit analysis rather than simply relying on comparison with other systems." Hydro also indicated that the criteria were only load orientated and should have generator location and constraints criteria as well. While Transend has provided the system security in planning criteria to OTTER, the criteria have not been established or agreed and are thus not binding.

In summary there was a limited understanding by key stakeholders of the proposed security and planning criteria in terms of their impact on future capital works, and the criteria have not been agreed for Tasmania. Transend has considered the criteria as an appropriate surrogate for forecasting projects that will pass the regulatory test.

6.6 Appropriateness of Capex Processes

6.6.1 General

Separate groups in Transend initially determine the development and renewal Capex.

Processes that are commonly used throughout the electricity industry underpin Transend's Development Capex determination. In preparation for the RP Transend engaged SKM to assist in the preparation of a formal development plan for the period, which considered load growth, customer connections, network security criteria and reactive support. Transend used this document as a basis of future development and refined the SKM cost estimates where more detail on a project is known. Under the current Tasmanian regulations, Transend follows a process of approval for regulated assets that includes external input. Some of the key steps in this process include an Annual Planning Review between Aurora and Transend and analysis of the Annual Planning Statement produced by the System Controller.

Once needs are identified and the Transend Board accepts the strategy, Transend undertakes public consultation to allow the identification of other network options, such as demand side management and embedded generation. The evaluated proposals and the different network options are prepared and sent to the Reliability &Network Planning Panel (R&NPP) after Board sign-off. Transend is not represented on the R&NPP. The Regulator determines whether the development is justified based on recommendation of the R&NPP. Transend then puts forward a Board business case and implements the project.

In reviewing the development Capex with Transend, GHD felt that the development section was understaffed, making it difficult to execute the necessary regulatory processes and at the same time address ongoing long term planning. Transend appeared to be appointing more personnel to address this.

Similarly for the Renewal Capex, Transend uses processes commonly used throughout the electricity industry. In particular it carries out continued management of assets through a number of asset management plans that cover transmission, substation and protection and control assets. These plans include outcomes of condition assessment reports and strategies to manage the assets including maintenance cycles and ongoing condition assessment. The Transmission System Management Plan (TSMP) is developed from these individual plans.

Transend produced evidence that alternatives are considered for development projects, particularly those that have been to R&NPP, where this process is necessary. Evidence has been provided of consideration of some alternatives for renewal projects. In a number of cases, further investigations are proposed to identify more cost-effective solutions to asset renewal.

GHD expects that Transend will rapidly develop new approaches to renewals through implementation of new technology, which will deliver reductions in Renewals Capex over the RP, although.

Transend has listed many techniques, processes and tools in its various Asset Management Plans that are being investigated by Transend or proposed for investigation over the RP. The effect of implementation of new technology on costs is not possible to determine at this stage.

While these processes are technically sound GHD is of the opinion that some of the business decisions are lacking in areas such as risk-based assessment. There does not appear to be full consideration providing alternative levels of service, in order to provide a rational basis for deciding tradeoffs between cost, timing and risk in conjunction with its stakeholders.

6.6.2 Assumptions

As part of the review GHD undertook an independent load forecast. The outcome indicated that the assumptions used by SKM in determining the development plan were generally appropriate, with the exception of the North East of Tasmania, where the independent forecast indicated lower load growth than SKM. The sensitivity analysis of the load forecast carried out by SKM indicated that load growth was not a significant factor to the transmission network.

While there has been in-principle agreement to Transend's security and planning criteria by Aurora and Hydro, concerns were expressed that the impact of these criteria on Transend's capital program needed identification before sign-off. No other customers were involved in this process. If the total improvements are not warranted, i.e. customers aren't willing to pay for the improvements, then some of the capital works may not be justified.

6.6.3 System Adequacy Assessment

Transend has a formal planning process in place that involves Aurora and the System Controller. These reviews indicate the adequacy of the system and Transend's response to those inadequacies.

GHD is of the opinion that Transend's processes in place for determining system adequacy are appropriate.

Transend has in the past been applying the market test to each project because it did not have a rigorous set of criteria for motivating reliability based network augmentations. Now Transend has set up security and planning criteria, a number of projects will be developed on the basis that they are needed to meet the minimum network performance requirements. The regulatory process as it currently stands is that a security/reliability augmentation is not disputable by the Regulator. If Transend customers do not agree with the criteria then they could be paying for levels of security and reliability they do not want. It should be noted that in the Application only two development projects could possibly fall into this category. These are George Town 220kV and Sheffield Security with a total budget of $6.5 million. Further discussion is provided in Section 6.7.2 of this report.

6.6.4 Cost Bases

Transend has provided evidence of its costing methodology for capital expenditure programs. For the development expenditure Transend has primarily used unit costs provided by SKM in the review of the development project program. GHD has reviewed these rates and found that they are appropriate for the purpose they were used. Transend has refined the costs for the some of the projects where it has experience of similar works.

The renewal Capex has been costed on a combination of known costs for similar jobs and SKM unit costs. Using unit cost is seen as appropriate for the development of the project estimate as the actual costs will range above and below the costs used. This will tend to even out over the whole program.

Project cost estimates include allowance for design, project development and finalisation, project management and administration. Rates used are based on consultant rates and hence include all overheads.

GHD has reviewed some of the projects by carrying out an independent estimate based on the works as advised by Transend. This confirmed that the overall costs used by Transend are appropriate.

6.6.5 Efficiency of Project Delivery

Projects are undertaken under different mechanisms depending on the size, scope and type of expertise required for the project. The mechanisms include:

- Competitive tendering of major construction projects
- Allocation to the O&M service provider, Aurora, for small construction jobs.

These practices are under review to attempt to optimise the balance between competitive tendering and the need to maintain a critical mass of work flowing to Aurora, considering the specific Tasmanian context of the business.

These processes are considered appropriate and efficient.

6.7 Development Expenditure

The main drivers for Transend’s development Capex are stated as:

- Load forecasts
- New customer connections
- New generation projects
- System security criteria
- Code compliance

Transend has had a development capital works program in place since 1998, continuing on with previously identified projects as well as programs identified since Transend’s formation. However, to identify the development capital projects for the RP, SKM was engaged to assist Transend.

Transend identified a number of development projects and put them into two categories: those with close to 100% probability of occurring during the RP which were designated as ‘fixed’ projects, and those with 10% to 80% probability of occurring, designated as ‘variable’ projects, which are further discussed in Section 6.7.4.

GHD has assessed the fixed projects and as can be seen from the summary in Table 6-7, the projects are in GHD’s opinion justified with some changes to timing, but still within the RP.

Table 6-7 Review of Transend Fixed Development Projects (2002/03 $m)

	Jan to Jun 2004	2004-05	2005-06	2006-07	2007-08	2008-09	Total
Application Proposal	2.8	43.2	14.3	48.3	0.6	0	109.2
GHD Assessment	2.8	43.2	10.3	45.8	4.6	2.5	109.2

Each category of development projects is further dissected below.

6.7.1 Load Growth Projects

Transend has proposed 10 fixed development projects over the RP. Of these, five projects have load growth as one of the drivers. This is combined with other drivers; being either customer development requirements (in each case Aurora), Code compliance and/or security criteria. Part of the process includes submission to the Reliability and Network Planning Panel (R&NPP) for endorsement. The R&NPP recommends on the basis that the proposed project satisfies the regulatory test. The project is then determined by the Regulator as to its need. It is usual for the Regulator to agree with the R&NPP endorsement. This Regulator approval is for projects starting construction within 12 months. A summary of each project and its approval status is provided in Table 6-8. All the projects listed in Table 6-8 as indicated endorsed by R&NPP have or will soon be determined by the Regulator as being required.

Table 6-8 Fixed Load Growth Projects

Project	Brief Description	Drivers	R&NPP Endorsement	Expenditure (rolled in) over RP (2002-03 $m)
Southern Augmentation Project	Provides a second line into Hobart area and the southern part of the Transend network. This increases security of supply and allows for load growths.	Load forecasts Code compliance Security Criteria	Yes (Note: Regulator has approved 110kV portion only which is to commence construction within 12 months)	55.40

Project	Brief Description	Drivers	R&NPP Endorsement	Expenditure (rolled in) over RP (2002-03 $m)
Norwood – Scottsdale -Derby Redevelopment	Replaces old plant (greater than 65 years old), improves load capability of supply and increases security of supply such that loss of one line will not affect supply.	Load forecasts Code compliance Security Criteria	Yes	17.45 (Note this project starts before the RP)
Mowbray 110/22kV substation	Part of overall Launceston upgrade to cover load increases and area development	Customer Development Load forecasts	Yes	8.25 (Note this project starts before the RP)
Risdon 33kV development	Provides 33kV into Hobart area for Aurora Hobart Area Supply Upgrade	Customer Development Load forecasts	Yes	8.43 (Note this project starts before the RP)
Creek Rd 33kV connections	Provides 33kV into Hobart area for Aurora Hobart Area Supply Upgrade	Customer Development Load forecasts	Aurora initiated project so R&NPP endorsement not applicable for Transend.	0.24 (Total project cost $0.35m. Note this project starts before the RP)

Transend advised that the drivers, importance and customer commitments have determined the timing of the projects. The timing reasons as advised by Transend are summarised in Table 6-9.

Table 6-9 Timing Basis for Fixed Development Projects

Project	Timing
Southern Augmentation Project	There are existing issues of supply security and the project should ideally be in place now. The completion by 2006/07 with start in 2003/04 is based on what is believed to be realistically achievable. The need for the 220kV component, which accounts for about half of the projected costs, is subject to confirmation that gas-fired generation is not economic in the Hobart area.
Norwood – Scottsdale -Derby Redevelopment	As indicated load is a driver currently causing an inadequately rated radial line under certain conditions. The assets are also aged. Aurora have also requested for an increase in security. A December 2004 target date has been advised to the R&NPP.
Mowbray 110/22kV substation	This substation was originally planned for commissioning in 1999/2000 and other substations are currently at risk of overloading due to delays in getting the project underway. The delay has been in the planning approval process. These approvals have now been obtained and the project is planned for completion in quarter 3 in 2004. The DA requirements to underground sections of the line have caused an increase to the original project cost of $3 million.
Risdon 33kV development	This project is being driven by Aurora redevelopments to manage increasing loads. The conversion to 33kV will be driven by Aurora's change of substations to 33kV. Aurora's request was for early 2004. The current program is October 2004 for the first transformers and full substation completion by April 2005.
Creek Rd 33kV connections	This is similar to Risdon in that the works are for Aurora network changes. The works are relatively minor and are staged over the next three to four years completing in 2005/06.

GHD's independent forecast suggests that the load growth in the eastern area is lower than used by SKM or those predicted by Aurora. The major project affected by this is the Norwood - Scottsdale - Derby Redevelopment. It is GHD's opinion that this finding would not alter the development significantly as the line already has problems with the load and Aurora has requested the security increase.

As indicated by Transend to the Tasmanian Government Joint Advisory Panel in November 2001 there are no Capital works projects for the connection of Basslink. The necessary works to connect Basslink are subject to an agreement between the Basslink developer and Transend. It is understood by GHD that the developer funds the Special Protection Scheme (SPS), which is the major part of the project impacting on Transend's network. Basslink is programmed to be complete in November 2005.

The Southern augmentation project was qualified by the R&NPP in its endorsement on the 220kV component as Transend was still having discussions with a developer on a proposed gas fired power station. This may avoid some of the augmentations, but the indication to date is that the power station project is not commercially viable and as such unlikely to occur. As the Commission has a claw back mechanism on Capex it is considered prudent to allow the whole projected expenditure.

GHD has assessed each of the fixed development projects and taking into account the status with the R&NPP and OTTER is of the opinion that the timing, the cost basis, the load forecasts used and scope of works is appropriate.

6.7.2 Code Compliance Projects

Transend has identified a number of projects to address existing security and code compliance issues. The security is based on the new Security Criteria that have been developed by Transend. These projects are summarised in Table 6-10.

Table 6-10 Development Code Compliance Projects

Project	Brief Description	Drivers	R&NPP endorsement	Expenditure (rolled in) over RP (2002-03 $m)
Reactive support	Installation of capacitors at various locations to reduce current reliance on Hydro generators	Code Compliance Security Criteria	The Chapel Street reactive support has been given R&NPP endorsement. The reminder of the locations have not been to R&NPP	6.85 (Note the Chapel Street project should be complete before the RP; its costs ($3.2m) are therefore not included.)
Smithton second circuit	Establish a second circuit on existing tower to duplicate supply between Port Latta Tee and Smithton	Code Compliance Security Criteria	Yes	1.60 (Note this project starts before RP.)

Project	Brief Description	Drivers	R&NPP endorsement	Expenditure (rolled in) over RP (2002-03 $m)
George Town 220kV Bus rearrangement	Implement breaker and a half arrangement in line with its importance as a major node due to Bass Link and Bell Bay upgrade and usage	Code Compliance	No, project is only in concept stage.	3.50
Sheffield Substation Security	Security improvements as all generation form Farrell area passes through this one location. Load flow is currently in excess of 500MW	Code Compliance	No, project is only in investigation stage.	3.00

Transend advises that the business drivers, importance and customer commitments have determined the timing of the projects. The timing reasons as advised by Transend are summarised in Table 6-11.

Table 6-11 Timing of Code Compliance Projects

Project	Timing
Reactive support	There is urgent need for reactive support in the south of Tasmania due to the current reliance on Gordon power station. The other projects have been staged over the period 2004/057 to 2007/08 based on what is believed to be realistically achievable.
Smithton second circuit	This project has an approved business case with a completion planned for early 2004.
George Town 220kV Bus rearrangement	This project has been identified as necessary technically but timing has only nominally been put in place as completion in 2006/07. This is for 220kV only; 110kV is programmed for after the current RP.
Sheffield Substation Security	The System Controller Planning Statement has highlighted the project as a security issue to guard against severe system disturbances for a 220kV busbar fault. Transend has nominated 2005/06 as timing for the works.

GHD is of the opinion that the reactive support program has been justified from a technical perspective and is required for Transend to meet the Tasmanian Electricity Code (similar to National Electricity Code) Schedule 5.1 which requires “The voltage control criterion is that stable voltage control must be maintained following the most severe credible contingency event. This requires that an adequate reactive power margin …”. The costs are based on previous works and budget quotations, and are considered reasonable.

The George Town and Sheffield projects appear to be technically appropriate but timing or scope has not yet been fully defined. It is not clear as to what effects will occur if these projects are delayed. However, if delays were introduced the technical criticality and timing is such that the projects would still occur in the RP.

In its assessment of capital expenditure GHD is of the opinion that the estimated cost is appropriate, but has delayed the expenditure by 2 years so that it occurs in a period of lower capital expenditure, than currently programmed.

6.7.3 NEM Entry Projects

Transend has identified a number of projects to facilitate entry into the National Electricity Market. The overall project, with a capital cost expenditure in the RP of $4.06m out of a total project cost of $5.05m, is designated as Tasmania Wholesale Electricity Market (TWEM). It was identified from a project team formed by Transend in August 2001 with the purpose of:

- Participating in the establishment of TWEM framework
- Ensure readiness for NEM entry when Basslink comes on line

Transend is expected to join the NEM in May 2005 about 6 months before the completion of Basslink.

The individual projects, timing and nominated costs are summarised in Table 6-12.

Table 6-12 NEM Entry Projects

Project	Capital Cost in Revenue period. (2002-03 $m. Cost in brackets total project cost)	Timing
Install NEC compliant wholesale metering at Transend/Aurora interfaces	0.90 (1.50)	2002/03 to 2004/05
Quality of supply monitoring for NEC Schedule 5 compliance	0.09 (0.30)	2002/03 to 2003/4
Replace field transducers associated with state estimator to meet NEMMCO requirements	0.57 (0.75)	2002/03 to 2004/05
Install back-up protection schemes to prevent system collapse in event of non-credible contingencies, required under NEC Schedule 5	2.50 (2.50)	2004/05 to 2005/06

GHD considers that these projects need to be carried out to allow entry to the NEM, and their scope and costs are reasonable. The timing of the works is dependent on the NEM entry date.

6.7.4 Variable Development Projects

Transend has made the Application on the basis that the variable projects, i.e. those with less than 100% probability of occurring, are to have costs reimbursed (or "passed through") at the actual cost if and when they eventuate.

Transend has indicated that as it assumed that these would be passed through at actual cost, the rigour in determining all the projects, scope and estimating the costs has not been applied to the same degree as the fixed projects.

Given that they are budget estimates and have been independently determined by SKM for Transend, GHD believes the estimates are appropriate for a weighted probability of occurrence costing approach. None of the variable projects have been subjected to a Regulatory Test.

Transend has calculated the total capital expenditure for the variable projects at $149.60m over the RP, with $69.57m or 46% occurring in the last financial year of the revenue reset period, 2008/09. Using a probabilistic weighting the total weighted expenditure is $59.75m.

The Commission has directed GHD to establish a reasonable level of Capex for the projects, considering their probably of occurrence, and on the basis of meeting the regulatory test.

There are a number of the projects related to generation connection including wind, hydro, gas, wood-to-waste energy etc. It is not clear as to the determination of benefits of the regulated (shared) assets, which are proposed for augmentation only because of the generation development. However, on the basis that these projects will deliver specific benefits to individual companies it appears unlikely that they would pass a regulatory test. During review, GHD noted that some projects in the Application provide for both new generator connections and demand growth, and include costs for the connection assets in the Transend substations. The generators are allocated costs for the transmission line to the substation but do not appear to be allocated costs for the new connection asset in the substation.

Where appropriate, these connection costs have been excluded by GHD, on the basis that this component at least would be unlikely to pass a regulatory test. It is recognised that the assets will be owned and maintained by Transend and will be subject to regulation.

GHD is of the opinion that some of the projects indicated in the RP as variable projects may occur and that it is appropriate to make some allowance for Capex. The expenditure level recommended by GHD is calculated by removing the expenditure for the generation connection and related projects and projects based on high load growth. The probability of many excluded projects is also very low and their timing is near the end of the RP. A summary of the projects and GHD's recommendation follows in Table 6-13.

Table 6-13 Variable Development Projects Review

Project	Description	Probability	Timing	GHD recommendation (where included would be at weighted value)	Expenditure over Revenue Cap Period (2002-03 $ million)
Farrell - Georgetown 2008	Required for new 220kV line with greater than 150MW wind	0.1	2007 to 2009	Exclude	40.22

Project	Description	Probability	Timing	GHD recommendation (where included would be at weighted value)	Expenditure over Revenue Cap Period (2002-03 $ million)
Farrell - Georgetown 2009	Required for new 220kV line with greater than 150MW wind	0.3	2008 to 2009	Exclude	40.22
Upgrade circuits to Smithton	Re-conductor 220kV line for 70km if 136MW stage 3 wind generation at Woolnorth	0.8	2005 to 2006	Exclude	6.40
Smithton to Sheffield	Required for new 110kV line with suggested wind generation at Woolnorth and Robbins Island/Jims plains	0.1	2007 to 2009	Exclude	39.92
Reactive Support Georgetown 30MVAR st 2	Required if high number of wind projects proceed	0.1	2008 to 2009	Exclude	0.90
Reactive Support Georgetown 70MVAR st 1	Required under certain conditions of 450MW export on Basslink	0.4	2007 to 2008	Include	2.10
Mt Nelson Substation	New substation required if high load growth scenario occurs	0.12	2008 to 2009	Exclude	7.06
Wynyard area upgrade	New substation required to feed projected industrial load	0.4	2006 to 2007	Include	4.79
Hadspen transformer augmentation	Required for load growth in Launceston/Trevallyn area	0.8	2006 to 2007	Include	4.90
Lindisfarne transformer augmentation	Required for greater than low load growth scenario	0.12	2006 to 2007	Exclude	3.30
Hydro Tarraleah/Tunga project stage 1	Hydro proposes to convert output voltage at Tarraleah power station	0.8	2004 to 2005	Exclude	8.50(total project $8.70m some work prior to RP)
Hydro Tarra/Tunga project stg 2	Hydro proposes to convert output voltage at Tarraleah power station	0.48	2006 to 2007	Exclude	6.30

Project	Description	Probability	Timing	GHD recommendation (where included would be at weighted value)	Expenditure over Revenue Cap Period (2002-03 $ million)
NE –Musselroe	Upgrade cost for Norwood – Scotsdale – Derby for Musselroe wind output	0.8	2004 to 2005	Exclude	11.00
Southwood connection to Knights road	New substation and transmission line for wood waste generation and Aurora customers	0.8	2004 to 2005	Include as Aurora customer connected to new substation. Generation connection asset is only small part of cost.	7.37
Test Energy Brighton	Connection of Brighton waste to Energy at 11kV	0.48	2006 to 2007	Exclude	0.20
GT Waste Energy	Green waste to energy plant	0.48	2004 to 2005	Exclude	0.20
Various generation projects	Robbins Island, Woolnorth, Heemskirk, Musselroe, Bell Bay 350MW, Duke Southern power station	0.32	2004 to 2009	Exclude	4.95
Aurora additional feeders	Aurora has indicated that they will possibly need an additional 30 feeders during RP	0.48	2005 to 2006	Include	1.50

Table 6-14 indicates GHD's recommended amount of Capex allowance for the variable projects.

Table 6-14 Summary Review of Capex for Variable Development Projects (2002/03 $ million)

	Jan to Jun 2004	2004-05	2005-06	2006-07	2007-08	2008-09	Total
Application Variable weighted value	0	22.00	6.70	8.70	3.10	19.40	59.70
GHD Assessment	0	5.90	0.70	5.40	0.60	0	12.60

6.8 Renewal Expenditure

Transend has 45 substations and 10 switching stations located throughout Tasmania, with operating voltages ranging from 220kV to 6.6kV. The average age of the substations is 32 years, with 55% of the transmission lines constructed over 40 years ago and 20% constructed over 60 years ago. The effective assets lives used by Transend are consistent with those used in the transmission industry. Transend does point out that its renewals are based on condition-based criteria, not just effective lives.

Transend has defined renewal capital expenditure as involving the replacement, enhancement and refurbishing of existing transmission assets. Transend has a capitalisation policy in place that defines the difference between operating and capital expenditure. In general terms capital expenditure is expenditure that provides future economic benefits. This covers new assets, replacement of existing, increase in capacity and/or efficiency of an existing asset, extension of the useful life of an asset and increase in functionality of an existing asset.

As can be seen from Table 6-15 the major portion of the renewal expenditure is for substations. Transmission line expenditure is dominated by the Earth wire (OPGW) project, which is to increase reliability by providing earth wire cover over the entire network. Fibre optic cable is being installed in the earth wire to meet the TEC requirements for communication redundancy and increased reliability of communications circuits. Currently Transend relies completely on outsourcing for its communications. The cost for OPGW is on average $8 million per year over the period 2005/06 to 2008/09. This matter is further discussed in Section 6.8.2.

Table 6-15 also indicates GHD's assessment of allowable Renewals Capex. Details of the basis for the assessment are provided in the text below.

Table 6-15 Summary Review of Renewals Expenditure (2002/03 $ million)

	Jan 04-Jun 04	2004-05	2005-06	2006-07	2007-08	2008-09	Total
Application - Transmission lines	5.4	5.8	9.5	11.8	10.5	11.1	**54.1**
Application - Substations	11.5	24.1	29.1	26.8	26.3	22.9	**140.7**
Total Application	**16.9**	**29.9**	**38.6**	**38.6**	**36.8**	**34.0**	**194.8**
GHD Assessment	**16.9**	**29.9**	**38.6**	**38.6**	**35.8**	**29.5**	**189.3**

Transend has had asset management plans in place and has been reviewing them. For the latest review the basis for asset management is the Transmission System Management Plan (TSMP), which covers the period 2003 to 2009. This plan carries on the renewal program previously identified by the HEC prior to the formation of Transend but has included a comprehensive review of those previous plans along with new asset condition assessments.

This process is ongoing and the renewal program is based on the information to date and expected outcomes of further investigation. The process and documentation used to support the renewal program is technically comprehensive and the samples viewed by GHD show that Transend has examined each of its assets in detail to determine their future performance. A number of drivers have been identified for replacement including failure history, unreliability, excess maintenance requirements, industry knowledge on equipment premature failures, as well as other aspects. Transend advised the renewal program is largely driven by condition-based assessment rather than asset age. From GHD's review it would appear that much of the previous age-based assessment still appears to be used where new condition based programs are not developed. The documentation shows that independent organisations have been engaged to review some of the asset categories' condition to ensure Transend applies the appropriate methods for refurbishment and/or replacement.

6.8.1 Renewals Relationship to Asset Base

Transend's Application indicates $156.8 million of the renewal expenditure is for replacement. The opening regulated asset valuation is $521.6 million at 30 June 2001. This value is an optimised depreciated value that was derived from an optimised replacement cost of approximately $1,000 million. The replacement expenditure in the Application is equivalent to approximately 16% of the value of the assets being replaced. Given that 20% of the transmission route line length was built over 60 years ago, 15% of substations are over 45 years old, and other assets have more than 20% of them over the 45 years old the replacement value appears in line with the required replacements to keep a system at its current state.

GHD has carried out a check of the renewal expenditure in the Application against what would be expected if the assets were being renewed on age alone. This was carried out by using age profile data supplied by Transend, assuming that anything older than the nominated effective life minus 5 years, (to adjust to an end date of 2008/09) is replaced during the RP. The findings, summarised in Table 6.16 indicate that, for substation assets, if age was the only replacement criterion then the renewal Capex would be significantly more than in the Application. The transmission assets replacement program is relatively minor in expenditure terms and has not been investigated in the same detail by GHD.

Table 6-16 Age Based Comparison with Application Renewal Capex

Asset Class	Transend's nominal effective life (years)	Application Renewal Capex as a percentage of the Capex for an age-based replacement
EHV circuit breakers	45	91%
Network transformers	45	49%
Supply transformers	45	41%
EHV disconnectors	45	9%
EHV voltage transformers	45	168%

The anomaly in the above assessment is the figure for voltage transformers. Transend has advised that 25% of the voltage transformer assets have inherent design deficiencies so that younger as well as older assets are being replaced. This is considered appropriate.

6.8.2 Assessment of Renewals Capex

GHD's assessment of the renewal Capex is considered in each major expenditure area.

Substations

Major substation renewal spend areas are each considered in Table 6-17.

Table 6-17 Assessment of Major Substation Renewals

Asset group	Spend % of total over RP	Average age of assets (years)	Comments
Power transformers	14%	27	The spend on network and supply transformers is approximately equal. Transend has a comprehensive plan of replacement based on condition assessment. Majority of the replaced units will be over 50 years old at replacement.
EHV circuit breakers	9%	30	The majority of these are 110kV circuit breakers. Transend has a replacement program based on condition and reliability assessment. The majority of replaced units will be over 45 years old at replacement. Where substation development work is programmed the replacement has been delayed or brought forward to occur together.
HV switchgear	12%	34	The majority of this replacement is of old 22kV outdoor switchgear with indoor switchgear. Transend has had independent reports on condition carried out. The main drivers for replacement identified are substandard clearances, poor condition, maintenance intensive and lack of spares. The majority of replaced items will be approaching 50 years old at replacement.
Substation redevelopment	22%	32	The majority of the spend is on three substations. The projects take the opportunity to replace unreliable assets, rationalisation of assets on a cost effective basis over individual replacement.
Protection and local control systems	12%		This is a continuation of the protection replacement program identified prior to Transend formation. The initial program related to EHV relays, Transend has reviewed all relays and recosted the program. The program is largely to replace relays at the end of their life as well as meet TEC requirements.

While the documentation shows that the replacement program has been ongoing since 1998 there appears to be little work carried out in the last two years, 2000 to 2002, on 110kV circuit breaker renewals. There has been a concentration on 220kV. This workload aligns with the Capex in those years being significantly less than other years. The RP includes for renewal of 110kV and high voltage circuit breakers and associated equipment.

Documentation viewed by GHD for the replacement program of 110kV circuit breakers does not indicate drivers for all items. It appears that from the age of the equipment that the driver for these items is age not condition. The majority of these items are included towards the end of the RP. GHD believes that on the basis that more comprehensive condition assessment will be carried out on these items it may be possible to delay the renewal until the next RP. The number of circuit breakers involved is about 25% of total, which equates to approximately $3 million. GHD is of the opinion that the renewal Capex should be adjusted accordingly.

There is an error in the Application substation development costs for Creek Road development. The effect is to reduce the capital expenditure allowance in 2008/09 by $2.5 million. After taking this into account, the timing and cost basis for the substation development projects in GHD's opinion is appropriate.

Transmission Lines

The major components of the Transmission renewal capital expenditure are:

- OPGW installation is a major portion totalling $36.1 million. The main driver is the current lack of earth wire coverage on 110kV and 220kV transmission lines to protect against lightning. For transmission line voltages of 110kV and 220kV it is usual to design with earth wires to protect against lightning to improve reliability and reduce electrical stress on the transmission and connected substation assets. A number of Transend lines have not had this applied. Transend advises that its research shows two out of the four TNSPs in Australia have 100% earth wire coverage on their lines and the other two are moving towards this strategy. The optical fibre component increases the cost by 2 to 2.5 times. The business case for OPGW is not yet complete as installations currently underway are being used to provide further refinement of costing. Transend has used an independent consultant to assess the communication strategy and provide budget costs. These have been checked against Transend's quotations for a recent project. The main driver for OPGW is to meet TEC and NEC communication requirements in relation to security and overcome areas where the current system could fail at common nodes. GHD is of the opinion that technically the timing and cost basis is appropriate.
- Foundation refurbishment is 13% of total spend. This is a continuation of a current program that will remove all defective transmission tower foundations by the year 2008/09. The costs and methodology are well documented due to the amount of work currently undertaken.

In assessing the renewal expenditure it is not clear to GHD as to which renewals are being driven by the reliability criteria on which Transend has based its capital expenditure program.

Transend has advised that the majority of the forecast renewal is to maintain present levels of reliability rather than improve it. This cannot be verified on the information provided. To determine the validity of this statement would need a detailed study, which was beyond GHD's scope. However, GHD did note that reliability was rarely the only driver. Other drivers identified were obsolescence, compliance and growth.

Capitalisation Policy

Transend has proposed some amounts as Opex which were previously applied as Capex, primarily relating to substation overheads.

On the basis of Accounting Standards, GHD is of the opinion that some elements of these amounts have been incorrectly allocated as Opex. This matter is discussed in more detail in Section 7.7.

Incorrectly allocated amounts should be included in the Capex allowance for renewal and depreciated as refurbishment expenditure. These amounts are shown on Table 6.18.

Table 6-18 Reallocation of Refurbishment Costs to Capex (2002/03 $m)

Item	Jan to Jun 2004	2004-05	2005-06	2006-07	2007-08	2008-09	Total
Transformer Overhaul	0.50	1.00	1.03	1.00	1.00	1.00	5.53
Post Insulator Upgrade	0.06	0.12	0.12	0.12	0.12	0.12	0.66
Total	**0.56**	**1.12**	**1.15**	**1.12**	**1.12**	**1.12**	**6.19**

6.9 Non-Network Expenditure

The Non-network Capex proposed in the Application is summarised in Table 6-19. along with GHD's summary assessment. Commentary on each item is provided below.

Table 6-19 Summary Review of Non-Network Capex (2002-03 $ m)

	Jan to Jun 2004	2004-05	2005-06	2006-07	2007-08	2008-09	Total
IT systems	0.54	0.54	2.995	0.395	0.61	2.735	7.809
General Assets (Motor Vehicles, T&E, furniture)	0.318	1.030	0.350	0.635	1.03	0.35	3.713
Minor assets (AM systems, stds, etc)	1.834	3.267	2.016	0.412	0.412	0.308	8.249
Accommodation	4.310	2.100	0.10	0.10	0.25	0.10	6.969
Total Application	**6.996**	**6.938**	**5.461**	**1.542**	**2.302**	**3.493**	**26.731**
GHD assessment	**6.755**	**5.950**	**5.048**	**1.181**	**1.441**	**3.184**	**23.559**

The major expenditure in the IT systems is the 3-year replacement of hardware for the Network Operation & Control System (NOCS) project. This is costed at $1.5 million every three years, commencing in 2005-06. This is considered reasonable on the basis that the life of computer equipment is limited with expected replacement after about 3 years, and the warranty will have run out.

The major cost in the accommodation category is Transend's new premises, which already has Transend Board approval.

A major cost in the minor assets category is the Asset Management Information System (AMIS), which totals $6.8 million over the RP. Transend has surveyed other TNSPs and decided that the best course of action is to build on the existing AMIS. The cost estimate of $6.8m is based on the survey results of other TNSPs. Transend has appointed a Project Manager and will use other TNSPs to assist with the writing of the specifications.

Review of a sample of projects proposed under this category reveals the following issues:

- No allowance has been made for trade-in values for vehicle changeover. This amounts to an average $0.105m per annum or $0.575m over the RP. The annual amount should be reduced by approximately one third to allow for this.
- Transend has requested a total of some $2.098m for standards and procedures, strategies and policies so that they are readily accessible to all staff and contractors via intranet. The Transend estimate has been based on quotations from other TNSPs that have already carried out this type of work. GHD's expectation is that the development of such material is on the basis that it will deliver cost efficiencies in service delivery, and that Transend should already have many suitable documents in place. The amounts appear conservative and some 50% of this or $1.05m is considered reasonable.
- There is a total amount of $1.55m for future re-structural contingency and undefined miscellaneous items under network minor assets. On the basis that there are sufficient contingencies built into other amounts, including a $1.10m IT contingency, GHD concludes that this amount should not be allowed.

6.10 Capability to Deliver Capex Program

Transend indicated that the magnitude of the capital works program is achievable. Transend verified this in the following ways:

- Internal resources for both development and renewal Capex have been allocated to support project delivery. A mix of internal and external project managers are provided to meet the demands of the work program.
- External resources. Transend has made contacts with suppliers and service providers to review their capabilities to support Transend's forecast capital and operational program.
- There have been significant delays in gaining external approvals required for a number of the development projects intended to be commissioned last regulatory period. Transend advised that these approvals have now been achieved for the majority of the development projects enabling these projects to proceed. This has been checked against the Regulator's indication of status and they are consistent.

Transend's advice on not meeting the projected development Capex to date is due to delays in gaining approvals and lack of dedicated staff to projects.

While Transend indicated most external approvals have been achieved, GHD is concerned that this is not the case for some major components of projects such as the Southern Augmentation Project. The effect on the program could be delays, however as the fixed development projects are largely forecast to be complete by 2006/07, delays are unlikely to push the works into the next RP.

Transend was asked to advise similarly for the review of historical renewal expenditure versus budget and reason for not meeting targets. The response was that resource constraints have affected the implementation and there is a lag between providing resources and implementation. Transend is confident that the projected 2002/03 expenditure demonstrates that the higher levels of expenditure can be achieved. This has been checked and indicates that the Capex projected spend for 2002/03 of $42.92m is below the budget of $48.99m, although the asset roll-in projected at $52.99m approaches the budget of $54.66m. Another constraint on implementation has been postponed outages due to the low storage levels in Hydro dams which limits where generation is sourced. Now that Bell Bay has a gas-fired generator this constraint is largely alleviated.

In the absence of other delays beyond its control, Transend is considered capable of delivering the GHD assessed Capex forecast, especially given that the 2002/03 Capex amounts approach the forecast levels in most years of the RP, plus allowing for additional resources to meet any increase.

6.11 Accuracy of Timing

The majority of the development projects that have been included in the application are appropriately timed. Two projects, George Town 220kV and Sheffield Security have not been detailed in their timing and have been included in the period from 2005 to 2007.

Transend uses condition-based and reliability criteria for renewals. There appears to be some plant being budgeted on age replacement rather than condition or reliability criteria. This is for equipment towards the end of the RP that has not yet been subjected to full assessment. GHD has adjusted the capital expenditure for these to occur after the RP on the expectation that condition-based assessment will extend the asset lives beyond the nominal age given to them by Transend.

GHD is satisfied that processes are in place so that the timing of the majority of the Capital Expenditure is appropriately justified from a technical perspective.

6.12 Summary of Findings

GHD findings in relation to the capital expenditure for development, renewals and non-network are summarised below.

- Processes for technical assessment of Capex appear to be reasonable and the majority of the work is justified technically and appropriately timed. Cost bases for Capex estimates are appropriate as are project delivery mechanisms for Capex. Transend has been through an internal process of budget rationalisation that appears to be based on both a practical assessment of the capacity of Transend to undertake the proposed programs, and an overall check of the revenue expectations of the organisation. GHD is of the opinion, however, that business decisions generally need improvements in areas such as risk-based assessment and identifying the impact of deferring project implementation. There does not appear to be adequate consideration providing alternative levels of service, in order to provide a rational basis for deciding tradeoffs between cost and risk in conjunction with stakeholders or understanding of project residual risk.
- There does not appear to be sign off or agreement by the regulator or Transend customers on the security and planning criteria that Transend has used as the basis for some capital works. If the total improvements are not warranted, i.e. customers aren't willing to pay for the improvements, then some of the capital works may not be justified. The magnitude of this is not possible to define until some agreement on the criteria to be applied is reached. Transend has advised that the majority of the forecast renewal is to maintain present levels of reliability rather than improve it. To determine the validity of this statement would need a detailed study, which is beyond the scope of this review.
- Fixed Development Capex appears to be appropriate from timing, costing and technical justification. Two projects are concept only and timing has not been rigorously applied, however as they are technically justified it is unlikely they can be delayed beyond the RP.
- Transend has in the past been applying the market test to each project because it did not have a rigorous set of criteria for motivating security based network developments and augmentations. The regulatory process as it currently stands is that a project satisfies the regulatory test if it (1) meets an objectively measurable service standard with the project minimising the NPV of the project; or (2) maximises the NPV of the market benefit. Now Transend has established security and planning criteria for its own purpose it has justified projects on a measurable service standard. This assumes that the criteria reflect the underlying costs and benefits to customers of providing a certain level of system security. If Transend customers do not agree to the criteria, then the costs and benefits to customers for these levels of security are not proven. Possibly $6.5 million of development projects in the Application, George Town 220kV and Sheffield Security, fit into this category.

- Variable Development Capex projects have not been costed or scoped to the same detail as the fixed projects. The total forecast expenditure over the RP is $149.6 million. Using a weighted probability of project occurrence this reduces to $59.7 million. GHD recommends that some allowance on a weighted probability of occurrence be made. The projects associated with generation connection have been removed in GHD's assessment of Capex. Projects based on high load forecast scenarios are also recommended for removal.
- Renewal Capex has been primarily developed on the basis of condition assessments, but some asset renewal forecasts remain as age-based. The overall renewal forecast is less than what would be expected on age-based assessment alone. GHD is of the opinion that the renewal Capex should be adjusted for potentially extended life of some assets. An error in the substation development costs for Creek Road development also reduces the allowance in 2008/09 by $2.5 million. GHD expects that Transend will rapidly develop new approaches to renewals through implementation of new technology, which will deliver reductions in Renewals Capex over the RP, although the effect of this on costs is not possible to determine and hence no reductions have been made.
- GHD considers that Transend has incorrectly allocated some refurbishment expenditure to Opex. Reallocation of this expenditure to Capex results in an addition of $6.2m to Capex.
- Non-network Capex has been extensively reviewed. After adjustment for an omission for vehicle trade-ins and reduction of some contingency items and allowances, a net reduction of $3.17 million is considered appropriate. Similarly to renewals, GHD expects that more cost-effective solutions will be developed to address some Non-network projects, and the recommended reductions should have minimal impact on Transend's ability to deliver planned improvements.
- Transend is considered capable of delivering the GHD assessed Capex forecast.
- Based on the above findings GHD is of the opinion that a technically supported but unrationalised Capex forecast is as set out in Table 6-20**.** The values should be considered a maximum, except for development projects which have passed the regulatory test. Transend has not followed an appropriate practice of cost-risk trade-off or budget rationalisation process involving its customers, nor have the reliability impacts of any project been quantified. This means that the Capex rationalisation process must be undertaken on a subjective basis as part of the Commission's decision. The effect of an appropriate rationalisation process could be deferrals of projects or lower cost/service level solutions to projects, resulting in possible reduction in total Capex over the RP, in consultation with key stakeholders.

Table 6-20 Technically Supported Maximum Capital Expenditure (2002-03 $m)

	Jan to Jun 2004	**2004-05**	**2005-06**	**2006-07**	**2007-08**	**2008-09**	**Total**
Development							
Fixed	2.8	43.2	10.3	45.8	4.6	2.5	109.2
Variable	0	5.9	0.7	5.4	0.6	0	12.6
Total Development	2.8	49.1	11.0	51.2	5.2	2.5	121.8
Renewal	16.9	29.9	38.6	38.6	35.8	29.5	189.3
Reallocation of Refurbishment	0.6	1.1	1.2	1.1	1.1	1.1	6.2
Non-network	6.8	6.0	5.0	1.2	1.4	3.2	23.6
GHD assessed Total Capex	**27.1**	**86.1**	**55.8**	**92.1**	**43.5**	**36.3**	**340.9**

The above table does not provide for smoothing of Capex over the RP.

7. Operational Expenditure

7.1 Basis for Review

The Operational Expenditure (Opex) review is undertaken in accordance with the Terms of Reference outlined in Section 1.2 and with reference to the requirements set out in the Code, specifically Part B of Chapter 6, which requires inter alia that:

"In setting the revenue cap, the Commission must have regard to the potential for efficiency gains in expected operating, maintenance and capital costs, taking into account the expected demand growth and service standards; and the regulatory regime seeks to achieve an environment that fosters efficient use of existing infrastructure, efficient operating and maintenance practices and an efficient level of investment."

In this context, GHD needs to inform the Commission on Transend's ability to meet its current and future Transmission Service obligations, in particular, is Transend's Opex Application deemed to be:

- Adequate?
- Efficient?
- Appropriate?

The review is also required to analyse and comment in respect to the following:

- An assessment as to Transend's ability to achieve its targets to reduce controllable operating costs for each of the next five years commencing 1 January 2004.
- An opinion as to whether there is scope for additional efficiency gains.

Due to the significance of the proposed Opex increases, a number of approaches were used to assess the reasonableness of Opex, including:

- Review of historical trends and patterns in expenditure,
- Analysis of cost category breakdowns and detailed review of selected expenditure groups.
- Consideration of industry benchmarks, and
- Alternative approach to cost build-up using a combination of trend prediction on base activities, cost efficiencies and allowing for new or fully justified additional activities.

7.2 Accounting Practices

Analysis and assessment is reviewed after taking into account existing Commission principles and guidelines, previous decisions, and where applicable Australian Accounting Standards.

7.3 Separation of Regulated and Non-Regulated Expenditure

Transend advised that it does not have significant Non- Regulated Income.

7.4 Historic Expenditure Review

The Application contains insufficient historical financial data to enable a reasonable trend analysis to be undertaken. However, during various interviews with Transend staff, on request, some applicable historical data for the period 2000 to 2003 was provided. This enabled a still incomplete picture of the period 2000 to 2003 to be both determined and juxtaposed to the application data for the RP.

Table 7-1 Transend's Historic and Proposed Operating Costs 2000/01 to 2008/09

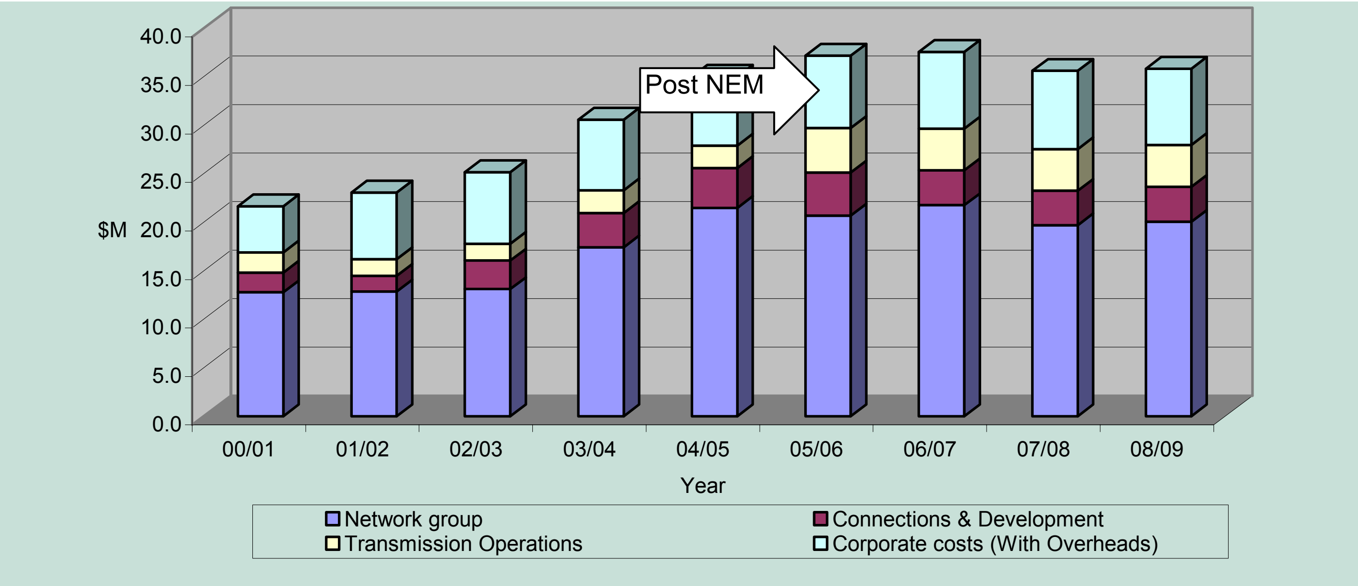
(Amounts are actual $ for 2001/02 and prior, and real 2002/03 $ for forecasts.)

Cost Category	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09
Corporate	4.47	6.66	7.40	7.29	7.10	7.47	7.90	8.07	7.84
Connections & Development	1.92	1.56	2.93	3.51	4.12	4.46	3.62	3.56	3.61
Transmission Operations	1.97	1.68	1.73	2.83	2.68	4.56	4.28	4.29	4.32
Network Group	12.06	12.49	13.11	17.42	21.46	20.68	21.75	19.68	20.04
Total (1)	**20.42**	**22.39**	**25.14**	**31.05**	**35.36**	**37.17**	**37.55**	**35.59**	**35.81**
Overheads Recovered	-2.13	-2.22	-2.45	-2.45	-2.45	-1.20	-1.20	-1.20	-1.20
Opex TOTAL	**18.29**	**20.17**	**22.72**	**28.60**	**32.91**	**35.96**	**36.35**	**34.39**	**34.61**

'(1) Excludes Overheads recovered

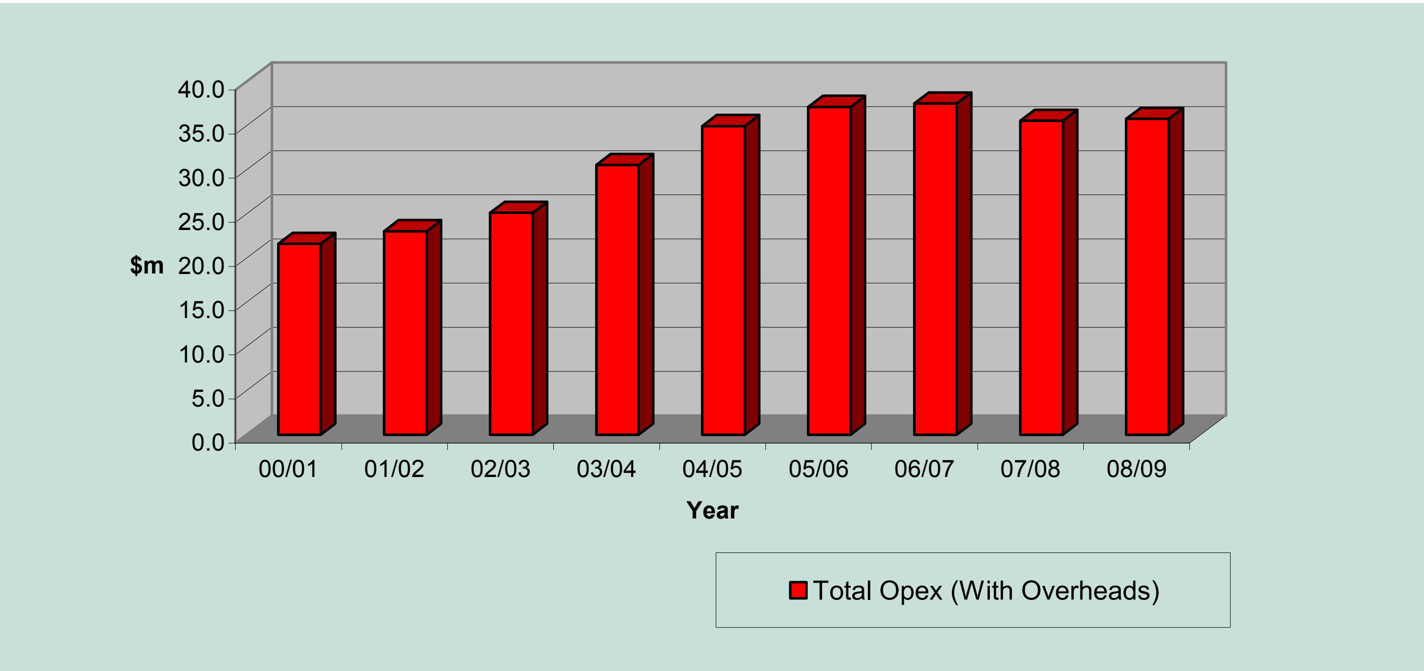
This is illustrated in the following Figure 7-1, after adjusting the historical figures to 2002-03 real dollars.

Figure 7-1 Historic and Future Operating Costs p.a. (excludes cost recovery) - by cost category (2002-03$m)



Alternatively this is illustrated in the following **Figure 7.2.**

Figure 7-2 Historic and Future Operating Costs p.a. (excludes cost recovery) – by total all cost categories (2002-03 $m)



All Opex categories are forecast in the Application to increase significantly over the next 5 years as illustrated above. Each cost category is separately assessed below.

In the Application (page ix), Transend states that its *“forecasting approach provides a robust ‘bottom – up’ assessment of costs rather than relying on cost performance in the recent past as a forecasting tool”.*

By discounting historical costs, the reader is left with an incomplete basis on which to judge the reasonableness of the costs presented.

It is appreciated that taking control of a complex business, such as Transend did in 1998, requires a complete review of all elements of the operations in order to set new forward moving plans and directions. It is also important that this is done against a backdrop of the entity’s historical performance. Loss of historical context can result in the loss of past efficiency gains and performance.

With respect to historic trends for the major cost category of maintenance expenditure, Transend appears to have undertaken considerable planned maintenance since its formation. In the earlier years, this was based on the processes, practices and plans developed by Hydro. However, in the last two years, Transend has started to implement its own risk and condition-based assessments (CBA). The future plans reflect this change of focus. When undertaking the CBA it is not always necessary to bring an asset back to its optimal capacity. A cost performance trade-off review should be undertaken, together with a business risk assessment of the benefits or otherwise of undertaking major maintenance/capital programs.

GHD considers that the historic trend indicating a proposed significant increase in Opex appears unwarranted on the basis of current relatively stable performance and low growth, even accounting for major changes to the scope of services proposed by Transend. This aspect is tested in the following text, and considers changes in scope, service performance and growth issues.

7.5 Overall Cost Analysis

In the Application, Transend presents high-level financial information supported by extensive narrative about future plans. There is limited additional financial information in the Application to support the extensive narrative, and consequently the financial impact of each major statement cannot be easily attributed to each event or cost element. This makes analysis difficult for interested stakeholders to come to a reasonable judgment on the veracity and appropriateness of the Application’s proposals. For example, one of the most significant new challenges for Transend within the review period will be its entry into the NEM. However, no total financial cost or impact analysis of NEM entry has been provided in the Application.

GHD has had access to further relevant information, including a detailed cost breakdown and believes that on review this shows a greater link between the narrative and the build up to the high-level expenditure forecasts in the Application. A review of each of the major cost categories is provided below.

7.5.1 Staffing Levels

When Transend commenced operations in 1998 the workforce overall consisted of 46 FTE staff with many activities outsourced. Some 24 staff were subsequently added with transfer of the System Controller. By 2003 staff had increased to 120 and is forecast to increase moderately throughout the review period to reach about 140 by 2008/09. The increase results from NEM entry/Basslink requirements; to bring in-house certain tasks that are deemed more appropriately managed by Transend staff; and to address the past difficulties that Transend has had in being able to implement prior approved allocations for development and renewals Capex.

7.6 Connections and Development Expenditure

Connections and Development (C&D) Expenditure is forecast to increase from the Application base (2003/04) figure of $3.51m by $0.6m in 2004/05 and a further $0.3m in 2005/06, a total of $0.9m in two years. These increased costs are primarily attributable to the costs associated with entry into NEM. Transend has no previous experience of this area from which to draw, and advised that ElectraNet's recent NEM Entry costs were used as a guide when developing Transend's forecasts. These NEM Entry costs have been separated from the base C & D expenditure and considered further in Section 7.10.

The Application indicates that another factor contributing to the C&D forecast increase is the need to boost resources to improve Transend's past underperformance in meeting customers' requests for connection to the grid and to meet future proposed connections. GHD's review process indicates that Transend has under-resourced this function, and other stakeholders have acknowledged this. Consequently, some additional resources appear to be justified, however, their extent is unclear and this aspect is further considered in GHD's overall trend assessment.

7.7 Network Expenditure

Network Group constitutes the largest Cost Centre within the Transend operations, representing over 50% of the total Opex Forecast. In the Application, again, Transend opted to present high-level Cost Category financial information supported by extensive narrative about future plans. Further relevant information, including a detailed forecast cost breakdown was subsequently provided, and is presented in Table 7-2 with a further breakdown of the other Network costs in Table 7-3.

Table 7-2 Network Group - Analysis by Cost Category (2002-03$ millions)[1]

Cost Category	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09
Transmission Line Maintenance	2.76	3.51	4.00	4.71	5.29	5.39	5.72	5.88	5.88
Substation Maintenance	6.00	5.30	5.93	6.10	6.46	6.45	6.42	6.19	6.44
Telecommunications Service Management	1.30	1.65	1.65	1.65	1.65	1.65	1.65	1.65	1.65
Outage Management	0.14	0.17	0.17	0.29	0.49	0.70	0.70	0.70	0.70
Project Administration	0.30	0.24	0.32	0.33	0.33	0.34	0.34	0.34	0.34
Other Costs[2]	1.57	1.61	1.72	4.35	7.25	6.15	6.91	4.92	5.09
Network Group Total	**12.07**	**12.48**	**13.79**	**17.43**	**21.47**	**20.68**	**21.74**	**19.68**	**20.10**

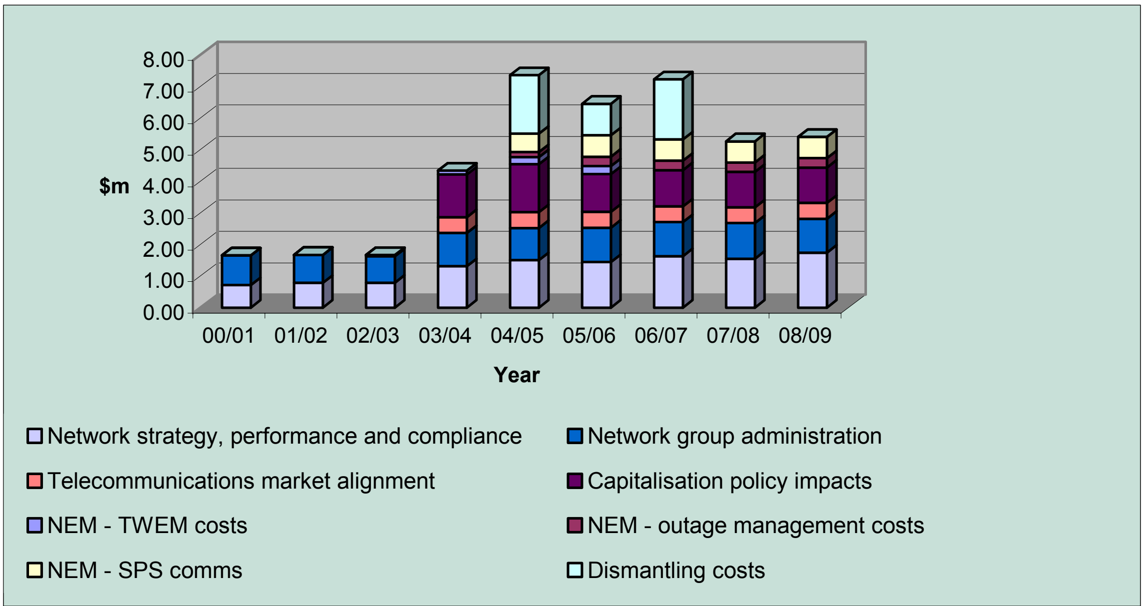
1. Historical actuals prior to 2002-03.
2. Other Costs are further detailed in Table 7.3.

Table 7-3 Other Network Costs - Analysis by Cost Category (2002-03 $m)(1)

Cost Category	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09
Strategy, Performance and Compliance	$0.67	0.76	0.79	1.31	1.50	1.44	1.63	1.55	1.74
Network Group Administration	$0.90	0.85	0.93	1.19	1.30	1.34	1.06	1.08	1.06
Telecom Services Mgt. Other				0.50	1.08	1.17	1.17	1.17	1.17
Capex to Opex				1.35	1.52	1.20	1.15	1.12	1.12
Dismantling Costs					1.85	1.00	1.90		
Total Other Costs	**$1.57**	**$1.61**	**$1.72**	**$4.35**	**$7.25**	**$6.15**	**$6.91**	**$4.92**	**$5.09**

(1) Historical actuals prior to 2002-03.

Figure 7-3 Network Group – Opex by Cost Category, (2002-03$m)

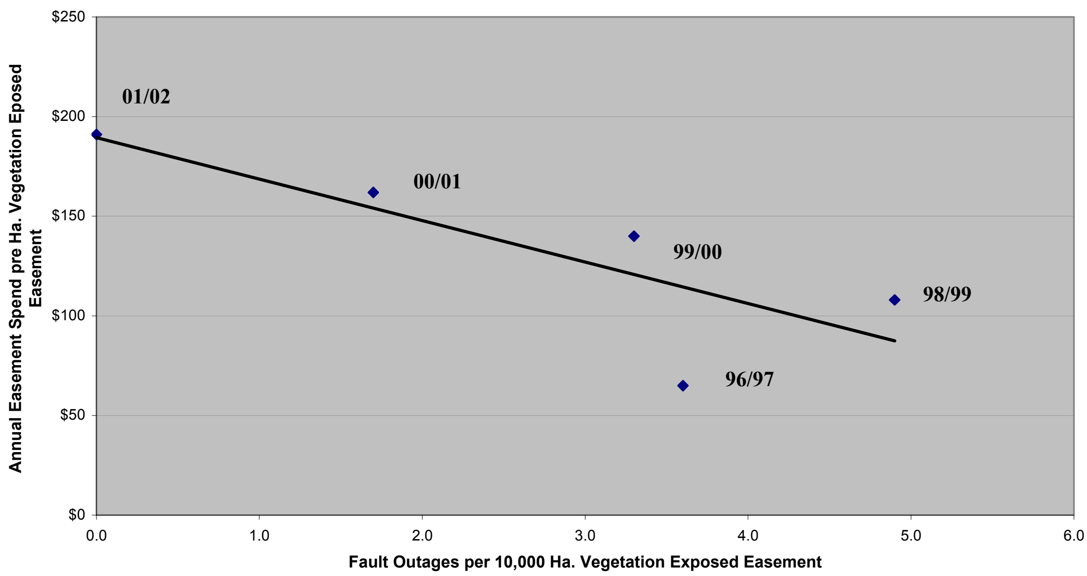


Of these Costs, for example, over 57% are attributable to Transmission Line Maintenance and Substation Maintenance. Some significant aspects are:

- **Transmission Line Maintenance** – These costs in 2001 were around $2.7m p.a and are forecast to steadily increase to $5.8 million in 2008/09, an increase of over 100%. Refer Table 7.2. The increases are primarily focused in the following areas:
  - Management Support - comprises the biggest growth in costs in Transmission Line Maintenance, rising from $0.93m in 2003/04 to $1.62m in 2008/09. This increase is mirrored in the general growth of staff numbers from the establishment of Transend in 1998 to meet identified sub-optimal performance in areas such as implementation of approved Capex, proposed increases in scheduled maintenance and a review of an earlier policy to outsource many activities. On review, management believes that these outsourced activities are more efficiently and cost effectively undertaken by in-house staff.
  - Support Assemblies: since taking over responsibility for Transend, management has undertaken a comprehensive CBA of all of the assets under its control. This includes Transmission Line Support Assemblies (Towers and Poles). In keeping with international 'best practice' standards that call for assets to be maintained in perpetuity, the costs proposed for this type of forward maintenance program in the Application have increased significantly. In the past, the transmission line maintenance program appeared to have been in more of a reactive mode, although evidence of some forward maintenance planning was in place. In the case of Support Assemblies this has resulted in costs being forecast to increase over the first four years of the review period to a high of $0.85m p.a. in 2007/08 and then decrease slightly in the last year to 2008/09 as the maintenance cycle decreases.

– Easement Management: Approximately $1.75m p.a. of forecast Easement Management expenditure has been attributed to vegetation control. Since disaggregation and the establishment of Transend in 1998, it has undertaken a comprehensive program to mitigate risks associated with previous vegetation management practices. In 1999 direct consequences of these previous practices included a major outage and a subsequent bush fire. GHD was advised that during the lead up to disaggregation, vegetation control had in Transend's opinion been inadequately planned and funded. When the current Transend management took control of the new organisation, one of its first priorities was to develop a strong vegetation control program under its Easement Management. This program has also taken into consideration improved environmental legislation and management requirements, i.e. owners are now very aware of the need to keep felled timber and vegetation off their properties – this often requires extensive and additional costly practices. From a low base, this program will require approximately $1.75m p.a. over the five-year review period. Transend has implemented a five-year vegetation control plan that calls for increased herbicide application. Transend expects this to result in long term reductions in present hand clearing costs. One of many other expensive factors within the plan is hand clearing that alone is expected to cost over $0.6m p.a. GHD has reviewed the plans and believe that they are reasonable. The impact of benefits arising from the increased expenditure of Easement Management is illustrated in Figure 7-4 provided by Transend. In this Figure the direct correlation between expenditure on Easement Management and the improvement in Fault (Reliability) Outage can be seen.

Figure 7-4 Annual Easement Spend vs Outages Due to Vegetation



- On the limited years of data available, the chart clearly shows the significant increase in outage events when appropriate vegetation controls are not implemented and funded. For example in the period 1996/97 through to 1998/99, the fault outage rate increased significantly from 3.5 faults to almost 5.0 faults per 10,000 Ha. of Vegetation Exposed Easement. In contrast, when a full program of vegetation control was implemented, faults gradually fell to zero by the end of 2001/02. The flow on positive effect was the avoidance of economic loss to production and environmental losses to the bush and animal habitat that far outweighs the extra costs forecast for vegetation control.

- **Substation Maintenance** – This represents over \$6.0m p.a. to manage and maintain 45 substations and 10 switching stations. This cost has been relatively constant at approximately \$6.0m p.a. from period 2000/01 to 2002/03 and is forecast to remain at this level through to 2008/09. GHD has reviewed these assumptions and believe they are reasonable. These costs are based on the issues identified in the Transmission System Management Plan 2003/09 and include:
  - Additional costs associated with dismantling, moving and reassembling of Transformers in 2004/05.
  - Mid-life overhaul of EHV Circuit Breakers
  - Additional costs incurred to meet new technology and information disclosure. Includes cost of testing performance of new SCADA equipment.
  - Additional costs incurred to comply with new OH&S requirements – including Fire Suppression and Crane Maintenance plus Climate Control Equipment Maintenance and improved Security Fence around assets identified at risk.

  Transend has forecast considerable increases in Capex for network transformer replacement that are expected to have a positive impact on future maintenance.

  However, this reduced maintenance is offset by Transend's move to Condition Based Assessment that has highlighted the need for increased maintenance on the remaining transformers that have not been replaced.

GHD has reviewed the above Work Plans and selectively analysed the reasonableness of forecast costs and believe that they are appropriate. The above cost categories, Transmission Line and Substation Maintenance, will represent over 60% of the Network Group Opex p.a. by 2008/09. The costs forecast by these two categories, which have been reviewed quite extensively and deemed appropriate, go a long way to explain the change in Transmission Line and substation Maintenance costs that were \$8.76m p.a. in 2000/01 and are forecast to rise to \$12.32m p.a. by 2008/09, as showin in Table 7-2. Some other cost increases are considered to be less supported. Those costs relating to NEM entry are considered separately.

Capex to Opex

Transend has reviewed its Capitalisation Policy, which GHD believes conforms to Accounting Standards. However, GHD is of the opinion that Transend has incorrectly applied the Capitalisation Policy to the treatment of Transformer Overhaul, and Post Insulator Upgrades.

GHD considers that these forecasts should not be treated as Opex but in fact should be treated as a Capex (Refer Table 7.4).

When Transend was established the company had an asset base that included 45 substations with an Effective Life of 45 years and an average age of 27 years at the time of formation of Transend. The assets were already over half way through their Effective Life with only 18 years remaining. As such the assets were already operating in a sub optimal state from age related deterioration. Therefore any major refurbishments would tend to increase the efficiency of the substation over and above its sub optimal status at the date of acquisition Transend's formation.

Similarly the Poles were already at a partially deteriorated state at the formation of Transend and any upgrade will increase the life of the poles.

Consequently any expense that increases an asset's efficiency including increases in effective life must be capitalised.

Table 7-4 Reallocation of Capex to Opex (2002/03 $m).

	Jan – June 04	2004/05	2005/06	2006/07	2007/08	2008/09	Total
Total Application Capex to Opex	0.69	1.52	1.20	1.15	1.12	1.12	6.80
Less GHD allocation to Capex (1)	0.56	1.12	1.15	1.13	1.12	1.12.	6.20
Amount Recommended	0.13	0.40	0.05	0.02	-	-	0.60

Note (1): Refer to Table 6.18

7.8 Transmission Operations Expenditure

Transmission Opex is forecast to increase from $1.97m in 2000/01 to $4.3m in 2008/09. This annual increase of more than 100% by the end of the review period 2008/09 is primarily the direct impact of participation in the NEM, forecast to be an ongoing cost of approximately $1.87m p.a. through the review period and beyond. During the two years prior to NEM Entry (2003/04 & 2004/05), the NEM Entry preparation costs are forecast to increase this Opex category by over an additional $1m each year. During the review Transend advised that it has built the forecasts primarily on discussions with other TSNP's which are already part of the NEM, in particular the experience of ElectraNet.

GHD considers that the Transend estimates are reasonable for clearly attributable NEM entry costs, except that no evidence of cost efficiencies was sighted. Other core activities are forecast to remain static.

Another major factor affecting the Transmission Operations cost structure occurs between 2004/05 and 2005/06 when a substantial proportion of the System Controller function is absorbed into Transend and the associated cost cannot be on-charged. These costs continue to be incurred as a result of Transend's need to retain system control for those assets not controlled by NEMMCO, and the decision to maintain a system security backup. The maintenance of the system security backup was extensively reviewed and deemed appropriate by the Tasmanian Government when the Basslink project was approved, however GHD considers that a closer analysis of the extent of the duplicate system should be undertaken. GHD's understanding is that other stakeholders expected these additional costs would be less significant. In the absence of adequate supporting information for this position, GHD considers that the Application forecast allowance for System Controller costs is appropriate.

An adjustment to the total Transmission Operations costs is required due to an inadvertent error of including depreciation by Transend. This was corrected following a request for reconciliation by GHD. The adjustment should apply to Table 7.6 of the Application, which should read Transmission Operations (Net) Jan-June 2004 of $1.3m and 2004/05 of $2.3m.

7.9 Corporate Expenditure

As stated in the Application on Page 83, the Corporate Expenditure is forecast to be in a more or less steady state from 2005/06 through to the end of the RP, with only one significant increase occurring between 2004/05 and 2005/06, during which period Transend is gearing up for its admission to the NEM. We have reviewed the assumptions and cost estimates and believe that the forecasts seem to be reasonable. It is noted that due to the current volatility in all insurance cover, Transend has requested that insurance increases over a static allowance of $0.95m p.a be treated as a pass through cost.

When Transend prepared the Application, the insurance industry was very volatile and future directions of premiums were impossible to predict. Since then the volatility has subsided and international forecast agencies such as Fitch Australia predicted that *"…the outlook for the Australian general insurance industry is stable"* (Fitch Australia 18 March 2003). As a consequence GHD does not consider it is necessary for Transend to be given leave to "pass through" insurance costs above $0.95 p.a.

However, the largest single factor impacting on costs is the transfer of the System Controller's Office and as a result overhead costs will not be recharged. Refer to comments earlier on the decision to maintain a security system backup.

GHD considers that Transend's Corporate cost forecast, including elements that may not normally be included by other businesses, is at the high end of expectations at around 20% of total Opex. Because of economies of scale, and some fixed cost components, to provide even basic Corporate services there is a core cost that one cannot go below to provide even a minimum of services. On balance, GHD considers that the Corporate amount is reasonable with the exception that no cost efficiencies are noted.

7.10 NEM Entry Costs

Throughout the application there are many references to the additional costs associated with the preparation and participation costs for NEM entry/Basslink. In total this constitutes a significant component of the increased costs incurred between 2002/03 and projected until the end of the review period 2008/09 with little significant cost savings being forecast. On request Transend extracted the financial costs included in its Application. This is shown in Table 7-5 below.

Table 7-5 Preparation for NEM entry/Basslink and Participation in NEM (2002/03 $ m)

Area	Activity	02/03	03/04	04/05	05/06	06/07	07/08	08/09
Preparation for NEM entry								
TSO	Implement SPS	0.03	0.05	0.03				
TSO	Develop Market Systems		0.30	0.48				
TSO	Model/limit equations		0.60	0.35	0.20			
TSO	NEMMCO/IT	0.10	0.13	0.08	0.08			
TSO	State Estimator Prep	0.04	0.08	0.08				
TSO	Prepare Entry	0.17	1.16	1.01	0.28			
C&D	Project B/up Sc Rev	0.03	0.05	0.05				
C&D	Quality/Sup. B'line	0.20	0.20	0.20	0.20			
C&D	Wholesale Energy Metering	0.05	0.05	0.03				
C&D	Prepare Entry	0.28	0.30	0.28	0.20			
NET	Protection Audit	0.05	0.10	0.08	0.10			
NET	Prepare Entry	0.05	0.10	0.08	0.10			
Corp	TWEM Project Team	0.59	0.59	0.59	0.95			
Corp	Change Management	0.06	0.06	0.06	0.06			
Corp	Prepare Entry	0.65	0.65	0.65	1.01			
NTC	Basslink Commissioning		0.03	0.35	0.35			
NTC	Prepare Entry		0.03	0.35	0.35			

Area	Activity	02/03	03/04	04/05	05/06	06/07	07/08	08/09
Total	**Preparation Costs**	**1.14**	**2.23**	**2.36**	**1.93**			
Participation in NEM								
TSO	Maintenance SPS				0.19	0.19	0.19	0.19
TSO	Maintain Limit Equations			0.18	0.18	0.18	0.18	0.18
TSO	NEMMCO Sys.				1.51	1.50	1.50	1.50
TSO	Participation in NEM			0.18	1.88	1.87	1.87	1.87
NET	Communications for SPS			0.58	0.58	0.58	0.58	0.58
NET	Perf. Reporting ACCC		0.10	0.10	0.10	0.10	0.10	0.10
NET	Participation in NEM		0.10	0.68	0.68	0.68	0.68	0.68
C&D	NEM Plan+APR			0.12	0.61	0.61	0.61	0.61
C&D	Participation NEM			0.12	0.61	0.61	0.61	0.61
Total	**Recurring NEM**		**0.10**	**0.98**	**3.17**	**3.16**	**3.16**	**3.16**
Preparation and Participation in NEM								
Subtotal	**Entry/ Ongoing.**	**1.14**	**2.33**	**3.34**	**5.10**	**3.16**	**3.16**	**3.16**
Plus	System Controller overheads not recovered				2.22	2.22	2.22	2.22
Total	**NEM Entry/Ongoing**	**1.14**	**2.34**	**3.34**	**7.32**	**5.38**	**5.38**	**5.38**

Total NEM entry /Basslink costs in the lead up to entry plus the remainder of the review period, 2002/03 to 2008/09, is forecast at $30.28m plus $5.38m p.a. ongoing participation cost from 2008/09.

By isolating these costs it can be seen that while Transend's costs are increasing the NEM entry/Basslink costs materially change Transend's core cost structure which by 2008/09 is up by 18.4% p.a (1). over its previous core activities due to entry into the NEM, With the NEM entry /Basslink cost isolated, the rise of the cost of other activities is not so dramatic, given management's need to make significant remedial maintenance, much of which has been discussed elsewhere in this review.

By recasting the Operating Costs, with the NEM entry /Basslink costs isolated, it can be shown that the core activities Opex has increased from $18.285m p.a. to $20.309m p.a. up 11%, rather than the presented gross figures in Application Table 7.9, page 84. This is not to say that the inclusion of the NEM entry /Basslink costs is incorrect. These costs are isolated purely as a means to enable a closer analysis of the significant Opex increase. GHD considers that the operational costs associated with Basslink should be directly recoverable from Basslink Pty Ltd. Preliminary costs for commissioning of Basslink should be capitalised and recovered from Basslink Pty Ltd

Note(1):18.4% is calculated by :$5.381/$29.219 i.e. $34.6 Table 7.9, Application, p.87 less the forecast NEM Participation cost.

As per the agreement outlined in the Application, page 17. Accordingly, the amounts considered as deductible from the Application are for Basslink Commissioning, maintenance of SPS and communications for SPS, which total $4.39m.

With respect to remaining NEM entry costs, all identified additional tasks have been allocated separate cost estimates. There appears to be some scope for reducing these costs through combining tasks, and where current tasks will be replaced by the new NEM entry tasks. This issue is further considered in the GHD trend review.

7.11 Efficiency Improvements

The Application provides a specific section relating to past efficiency gains, specifically those which can be attributed to the Tasmanian Wholesale Electricity Market project, initiated by Transend to manage issues associated with NEM entry. Other efficiency improvements were stated as difficult to identify, given the changes in scope for Transend's past activities.

There are numerous text references in the Application to the scope for future efficiency gains and comment that the impact of these gains has been incorporated in the expenditure forecasts. As the financial data presented in the Application is at a high aggregate level, GHD has requested quantification of how these efficiency improvements or cost savings have been built into the forecasts. Transend has not been able to provide significant information in this regard, and is unable to support its statements of incorporation of cost efficiencies.

For example, no evidence was provided to support statements in the Application such as *"These gains in efficiency are reflected in the O&M expenditure forecast for the Network group shown in Table 7.4"* (Application, p77). This particular statement cited gains from a variety of areas, many of which could be expected to deliver major efficiencies, that in turn should offset some of the forecast cost increases in other categories.

Transend advises, *"… quantification of future efficiency gains would require a consideration of a sub-optimal expenditure plan. It would be of questionable benefit to construct a sub-optimal plan for the sole purpose of separately quantifying 'efficiency gains' that are incorporated in the proposed expenditure plan."* GHD would expect that best practice budgeting in a commercial environment would demand an optimal plan be prepared on current practice, and then apply factors where possible to allow for future efficiency improvements in order to drive efficiencies and maintain competitiveness. These same processes should be expected from a monopoly provider to ensure, and demonstrate to its stakeholders, that it aims to deliver a cost efficient service.

7.12 Trends in Forecast

As discussed earlier, the absence of historical data in the Application impeded a trend analysis. When the additional data was provided on request, a significantly different perception of the trend was evident. Refer Table 7-1 Operating Costs 2000/01 to 2008/09.

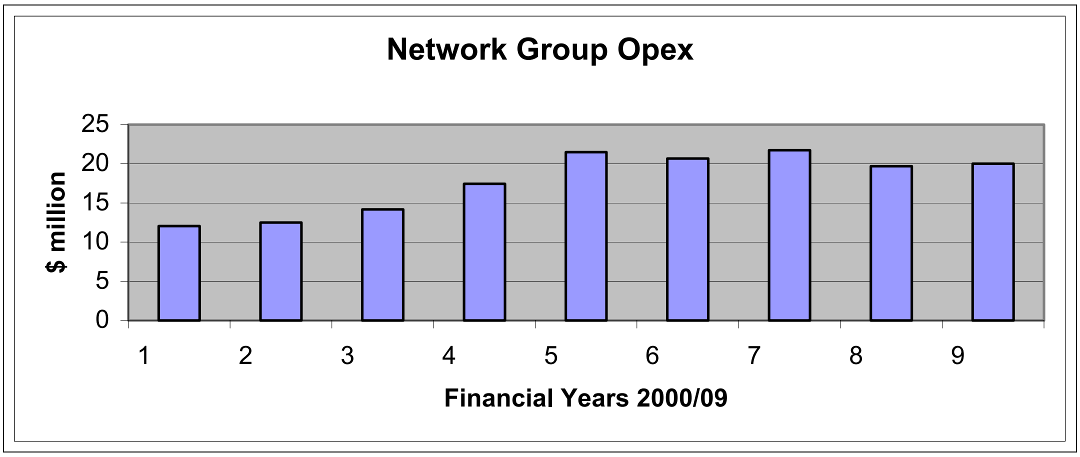
The largest major cost category, Network Group Expenditure rises from $12.06m p.a. to $20.10m p.a. from 2000/01 to 2008/09, an increase of 66%. Annual Expenditure in 2008/09 is projected to decrease from a high of $21.74m p.a. in 2006/07. Refer to the following Table 7-6**.**

Table 7-6 Network Group Opex 2000/01 to 2008/09 (2002-03 $m)

Expense	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09
Network Group	12.06	12.49	13.79	15.45	16.64	16.76	17.22	17.09	17.43
Network Group Other			0.04	1.98	4.83	3.92	4.52	2.59	2.59
Total	**12.06**	**12.49**	**13.83**	**17.43**	**21.47**	**20.68**	**21.74**	**19.68**	**20.02**

The increase in Network Group Opex each year from 2000/01 until completion of the NEM entry and the Basslink in 2004/05 are illustrated in the following Figure 7.5. The predicted ongoing annual costs to participate in the NEM of $5.38m p.a. plus the increase in vegetation control $1.7m p.a. accounts, in the main part, for the increase in Opex from the core activity costs in 00/01 at $ 12.0m. That is $12m p.a. (01/02) plus $5.8m p.a. plus $1.7m p.a. plus other expenses $0.5m p.a. equals $ 20m p.a. (average for the 4 years of the Application from 2005/06 to 2008/09).

Figure 7-5 Network Group Opex 2000/01 to 2008/09



The largest step jump in the overall Opex trend, increases from a projected $22.7m in 2002/03 to a forecast $28.6m in 2003/04. This increase of $5.9m p.a. includes an increase of $3.64m for the Network Group, of which the most significant increases are:

- Network Strategy, Performance and Compliance, up $0.52m p.a.
- Network Group Administration, up $0.26m p.a
- Telecommunications Service Management, up $0.50m p.a.
- Changes to Capitalisation Policy now treated as Opex, up $1.35m p.a.
- Transmission Line Maintenance, up $0.71m.
- Increased Substation Maintenance, up $0.17m p.a.

Overall Transend has undertaken a detailed 'cost plus' approach to its requirements to manage and operate the Network. However, no evidence of a comprehensive risk, cost-benefit or impact analysis was sighted. No clear evaluation of the consequences of undertaking an alternative course of action was considered. That is, a Condition Based Assessment (CBA) has been undertaken, but no assessment has been made to discover what the risk consequences would be if maintenance was delayed for 1 year or even longer. GHD is of the opinion that, as in the case of SPI PowerNet, more use should be made of historical data when projecting maintenance cost requirements. While GHD fully endorses the use of CBA, this must also be tempered with historical data and future Asset Management Plan rationalisation.

7.13 Grid Support Costs

Grid support costs have not been incurred by Transend to date, as they are not permitted under the current regulatory determination. These costs may be incurred in future when planned outages or deferred transmission augmentations result in requests to generators for changed generation output, or to customers for demand-side management. These costs are highly uncertain and Transend has requested that these costs be included as a pass-through item.

The Commission's previous Revenue Cap decisions indicate that it would prefer to treat grid support as a pass-through cost, although the Commission advised it is clearly preferable to provide for an amount if a reasonable estimate can be made.

Transend has indicated grid support costs may be in the order of $2m p.a. based on an analysis of the outages requiring grid support over the past year.

Whilst it is difficult to analyse the appropriate approach, GHD considers that the application of grid support costs is, at this stage, highly uncertain and consequently recommends a pass-through allowance, subject to certain conditions. These conditions should require that Transend justifies the amount of pass-through requested each year and demonstrates that the lowest net cost option was selected for the project.

7.14 Alternative Opex Trend Review

While it is acknowledged that Transend has undertaken a considerable amount of detailed analysis to support its Opex application, at the completion of GHD review it has been concluded that it is appropriate to present an alternative Opex forecast.

This forecast is based on the published 2001/02 financial results adjusted for one-off cost items to derive a base Opex, then forecasting a trend to allow for agreed new activities, less an efficiency improvement. The 2001/02 base is considered most appropriate in order to separate the impact of one-off or short term activities, such as TWEM. The forecast starts from an allowed historical 2001/02 base of $18.5m p.a. and provides for:

- CPI increase in 2001/02 costs to 2002/03.
- A modest performance improvement of 2% p.a. commencing in 2003/04.

The trend has allowed for the acknowledged increase in scope for additional tasks relating especially to NEM entry and participation, and increased maintenance activity and telecommunications costs. It should be noted that, in general, the full costs estimated by Transend for these activities has been included in this trend build-up. Some efficiencies could reduce future costs in these areas to allow for other, at this stage, unidentified tasks.

In summary, the additional costs allowed comprise:

- NEM entry and participation costs. These costs have been allowed in full excluding costs forecast for entry and participation into Basslink amounting to $4.39m. Such costs are considered recoverable from Basslink Pty. Ltd, NEM costs have been allowed in full even though some reductions are considered possible through combined tasking and replacement of current similar tasks, e.g for regulatory reporting and corporate management. Note that these costs will apply across all of the cost categories of Transend's Opex as detailed in Table 7-5.
- additional scope increases to Connections and Development activity of around $0.09M pa. (total $0.48m).
- additional telecommunications costs of $0.50m p.a. due to acknowledged low market rates during previous periods (total $2.75m).
- increased substation maintenance activity amounting to an approximate $1 million p.a. (total $4.98m).
- Capex to Opex allowance of total $0.60m due to changes to Transend's Capitalisation Policy, reduced for amounts considered as most appropriately allocated to Capex of $6.20m in total.
- increased easement management amounting to around $1.75m p.a (total $9.67m)
- dismantling costs of total $4.8m.
- allowance for reallocation of overhead costs after transfer of System Controller to NEMMCO, at $2.22m p.a. (total $11.10m).
- increased insurance premiums to $0.95m p.a..

Grid support costs are not included.

The suggested GHD alternative trend forecast for Opex is depicted in Figure 7-6and summarised in Table 7-7. It can be seen that on an adjusted basis the Transend Opex Application is an average $6.4m p.a over the GHD trend forecast represented by the area labelled Variance in Figure 7-6**.**

The total difference between Transend's Application and the GHD trend forecast is some $35.2m. Details of the build up of the alternative trend model are provided in Table 7-8. Additional allowance for Grid Support costs are not included.

Figure 7-6 GHD OPEX Trend Review Vs Application (Actual $m for 2001 and 2002, real $ 2002-03 for forecast)

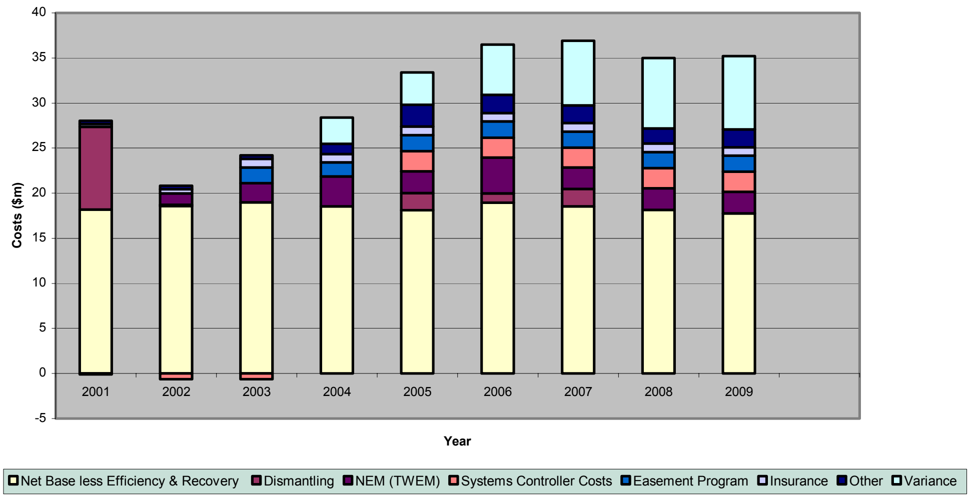


Table 7-7 GHD Opex Trend Review (2002/03 $ millions)

	03/04 6 months	04/05	05/06	06/07	07/08	08/09	Total
Transend Application	16.0	33.4	36.5	36.9	35.0	35.2	193.0
Suggested Adjustments	-2.9	-3.6	- 5.6	-7.2	- 7.8	-8.1	-35.2
GHD Review	**13.1**	**29.8**	**30.9**	**29.7**	**27.2**	**27.1**	**157.8**

Table 7-8 GHD Trend Analysis (Detail) (2002/03 $m)

TRANSEND		Published		Published	Adj Factor	F/cast	F/cast	F/cast	F/cast	F/cast	F/cast	F/cast
		2001		**2002**		**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Base Operating Costs		18.20		20.79	3%	21.41	21.41	20.99	20.57	20.15	19.75	19.36
Efficiency					-2%	0.00	-0.43	-0.42	-0.41	-0.40	-0.40	-0.39
Overheads Recovered				-2.22		-2.45	-2.45	-2.45	-1.20	-1.20	-1.20	-1.20
Easement Management Program						1.75	1.57	1.78	1.79	1.76	1.78	1.77
Sys Cont. Cost	8.24		8.50									
Sys Cont. Recharge	8.33		9.15									
SC Cost		-0.09		-0.65		-0.65	0.00	2.22	2.22	2.22	2.22	2.22
CAPEX to OPEX							0.13	0.40	0.05	0.03		
Connection & Development							0.02	0.09	0.09	0.09	0.09	0.09
Telecommunications							0.25	0.50	0.50	0.50	0.50	0.50
Substation Maintenance							0.32	1.05	0.99	0.96	0.68	0.98
NEM Preparation						1.14	2.23	2.36	1.93			
NEM Participation							0.07	0.05	2.05	2.39	2.39	2.39
Tas. Whls Elect Mkt.				0.67		0.50	0.50					
Tas. Elect Mkt.				0.58		0.50	0.50					
Insurance		0.30		0.46	105%	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Lease Pay		0.35		0.40		0.40	0.40	0.40	0.40	0.40	0.40	0.40
OPEX forecast incl, NEM		18.77		20.02		23.55	25.46	27.91	29.92	27.84	27.16	27.07
Projected OPEX for Rev. Cap		18.77		20.02		23.55	25.46	27.91	29.92	27.84	27.16	27.07
Dismantling		9.17		0.14			0.00	1.90	1.00	1.90		
OPEX Recommended		*27.94*		*20.17*		*23.55*	*25.46*	*29.81*	*30.92*	*29.74*	*27.16*	*27.07*

7.15 Summary of Findings

The main findings from this Review of Transend's Opex submission are:

1. Transend has developed its Application by a detailed text explanation to support its forecasts. The Application contained limited historical data and cost breakdowns to enable the reader to analyse the significance of each proposed new activity. To improve the process in future it is recommended that the Commission lay out the form of presentation and the support data that is required for future Applications to facilitate an appropriate review process.
2. While Transend has substantially reviewed its costs, it has made claims that cost efficiencies have been built into the Application. However, Transend advised that it was difficult to assess total efficiency gains against the historical expenditure for 2001/02, and quantification of how future cost efficiencies were built into expenditure forecasts had not been provided in support of the statements in the Application.
3. Limited evidence of a systematic risk/cost/benefit trade off or risk-managed approach to investment decisions was sighted. Transend indicated that prioritised issues were addressed and expenses were cut back to fit resources rather than undertaking a comprehensive risk/cost/benefit analysis.
4. The Application trend shows that Opex costs (in 2002-03 $m) will rise from $19.37m in 2000/01 to $34.61m at the end of the RP (2008/09), an increase of 78.7%.
5. The increase in the Application forecast Opex during the RP is due primarily to two major factors. (i) NEM Entry /Basslink that is forecast to cost $30.28m over the period 2002/03 and 2008/09, with a projected ongoing annual cost thereafter of $5.38m p.a., and (ii) Increase in Maintenance as a result of Transend's 'bottom up' review of the current condition of all of its Transmission Assets and the need to employ additional staff to improve its general management during the RP.
6. Processes for technical assessment of maintenance Opex appear to be reasonable and the majority of the work is technically supported by reasoned argument and/or CBA. There does not appear to be adequate consideration providing alternative levels of service, in order to provide a rational basis for deciding tradeoffs between cost, timing and risk in conjunction with stakeholders and supported by risk based assessment.
7. An increase in costs are incurred as a result of the need to provide system control functions and the decision to maintain a system control backup. The maintenance of the duplicate system was extensively reviewed and deemed appropriate by the Tasmanian Government when the NEM Entry /Basslink was approved.
8. Capex to Opex allowance of a total of $0.6m for the RP is due to changes to Transend's Capitalisation Policy, reduced for amounts considered as most appropriately allocated to Capex of $6.20m in total.

9. GHD has assessed an alternative Opex forecast determined from an allowed historical base of $18.5m p.a. for ongoing core activities, less the application of a 2% cost efficiency performance indicator, and allowing for the building block costs associated with new activities, such as increased substation maintenance, vegetation control and additional Transmission Line inspections, telecommunications, NEM preparation and participation costs, increased insurance premiums, system control overheads unrecovered, dismantling charges and other minor items. In summary the alternative trend analysis represents a recommended reduction in Opex of $35.2m in total for the RP. This is an average reduction of around $6.4m p.a. to the Transend Application.
10. The application of grid support costs is so uncertain that a pass-through allowance is most appropriate, subject to certain conditions. These conditions should require that Transend justifies the amount of pass-through requested each year, and demonstrates that the lowest net cost option was selected for the project, including grid support costs.

8. Regulatory Asset Base Roll Forward

8.1 Introduction

The opening Regulatory Asset Base (RAB) as at 1 January 2004 is accomplished by rolling forward the 30 June 2001 value of the opening asset base determined by the jurisdictional authority using an appropriate index, and including prudent capital additions and disposals and depreciation over the relevant period.

Transend submitted a RAB proposal in its Application, following this with supporting spreadsheets providing details of the proposed roll forward in accordance with the above approach.

With respect to the RAB value, Sinclair Knight Merz Pty Ltd (SKM) was appointed by Transend to undertake an asset valuation as at 30 June 2001, which was based on the Depreciated Optimised Replacement Cost (DORC) valuation methodology. Meritec Pty Ltd reviewed the resulting valuation upon request of the Tasmanian State Treasurer, and adjustments made to the valuation. The outcome of the review was a RAB valuation as at 30 June 2001 (in nominal $m) as per Table 8.1.

Table 8-1 Tasmanian State Treasurer's determination of the Transend asset base as at 30 June 2001 (in nominal $m)

Item	Opening asset base as at 30 June 2001
Substations	**190.2**
Transmission lines and cables	**209.3**
Protection and Control	**42.2**
Refurbishments	**0**
Land and Easements	**66.1**
Other assets	**13.8**
Total	**521.6**

The Commission is required to use this valuation as the RAB although comment is made on two aspects of the compilation of this valuation in the following text.

GHD's assessment of the Transend proposal has included a 'desk-top' review of the available information, checking for inconsistencies or aberrations within the data, and providing a recommended RAB with supporting commentary. While this assessment has relied on the provided data being correct, we have additionally reviewed random items to verify the data in some cases.

8.2 Transend Proposed Roll Forward Arrangements

In the Application submitted by Transend, a proposed roll forward asset valuation was included stating the closing asset base at $542.2m by June 2002, $581.7m by June 2003, and $603.8m as at December 31 2003. The spreadsheet Transend used to develop these values was provided to GHD and the methodology reviewed for prudency and accuracy.

In the spreadsheet provided, Transend listed the actual capital additions up to June 2002, and also listed projected capital additions up to 31 December 2003. It is recommended that the additions ending June 2003 be confirmed by Transend at the end of the 2002-03 financial year, along with any adjustments to the projection for the period to 31 December 2003, and those details be included into the roll forward. This will enhance the accuracy of the RAB.

8.3 Review Findings and GHD Proposed Roll Forward

Asset categorisation

A schedule of the assets, including the relevant asset class, replacement costs, asset life, depreciation profile and optimisation adjustments was provided by Transend in the spreadsheet. Samples from this spreadsheet were reviewed and there have been no noticeable discrepancies with the information provided by Transend.

Indexation

The CPI values used for the periods ending 30 June 2002 and 30 June 2003 are reasonable, with an 8 Capital City average used for the 2002 financial year at 2.84%, and an estimate of 3% used for the current financial year. For the 6 months leading up to 31 December 2003 an effective CPI of 0.97% has been proposed. GHD considers this to be a suitable index for the six months in question. The effective CPI used by Transend for Capex roll-in, factored for the 6 month period, was 1.95%. GHD considers a correction is required and a reduction of this CPI to 0.97% results in a decrease in the asset base at the end of the roll forward period by approximately $300,000 nominal, which GHD has included in the recommended asset roll forward schedule.

Depreciation profiles

The depreciation calculations included in the Transend RAB submission have been briefly reviewed and appear to be sound. Depreciation rates are appropriate. Various random calculation sequences have been checked for validity to consolidate GHD's opinion that the overall calculations are sound based on the data provided.

Accuracy check

As part of the asset categorisation process, the additions/deletions included into the roll forward were reviewed with respect to the accuracy and consistency of their inclusion. This involved the random checking of items included to ensure that they were appropriately reflected in the data provided. The areas of focus for this check were capital additions and disposals. The items checked were all deemed to be accurate, and whilst information was difficult to obtain, there was no evidence of definite inconsistency within the provided data.

Land and Easements

The RAB includes an amount of $66.1m in land and easements, which is broken down to $14.7m in compensation costs and $51.4m in acquisition costs. The inclusion of an amount for acquisition costs based on estimates is not consistent with previous Commission decisions, as usual practice is to allocate these costs to the Capex project e.g for transmission line costs. However, it is beyond GHD's scope to reconsider the RAB and the Commission may wish to assess this matter.

For the roll forward period, Transend has included zero depreciation of both the compensation value and acquisition costs of land and easements into the asset base roll forward, indexed at the CPI rate. Minor additions for new land acquired/to be acquired are included. This is shown in Table 8.2 below.

Table 8-2 Transend Land and Easement Cost Breakdown and Roll Forward (Nominal $m)

Item	Opening asset base as at 30 June 2001	Opening RAB for 31 Dec 2003	Influences on Roll Forward
Land (Compensation costs)			
Easements (land value)	11.5	12.3	
Substation Land	2.9	3.1	
Non-Grid Land	0.3	0.7	Includes additions of $0.343m from land purchases as well as CPI increases.
Sub Total – Land	**14.7**	**16.1**	

Item	Opening asset base as at 30 June 2001	Opening RAB for 31 Dec 2003	Influences on Roll Forward
Acquisition Costs			
Acquisition of Routes	35.8	38.3	
Acquisition of Sites	15.6	16.7	
Sub Total – Acquisition Costs	**51.4**	**55.0**	
Total of Land & Acquisitions	**66.1**	**71.1**	Appreciation of land & acquisition costs at CPI rate adds $4.597m in total.

Transend's proposal for the treatment of acquisition costs is not consistent with treatment in the Commission's decisions on SPI PowerNet and ElectraNet. In those cases the Commission only considered it appropriate to include the indexed historical costs of easements, and acquisition costs were considered to be included with the depreciating asset historical costs.

GHD considers the treatment by the Commission in previous decisions to be appropriate, and recommends that the acquisition costs (if allowed in the opening asset base) be amortised in line with the related constructed assets. This has the effect of reducing the RAB by $5.9m.

Revaluation of Fully Depreciated Assets

A check was made to see if any in-service assets which had been fully depreciated prior to 30 June 2001, were revalued and reinstated in the opening asset base.

GHD found that some $34.8m of assets at the 30 June 2001 are in this category. These assets were originally assigned a 5 year life under a DORC methodology except for Transmission Lines, for which a $0.5m amount was allocated a 15 year life. This treatment is appropriate, but the longer asset life will act to slightly reduce the amount depreciated during the roll forward compared to a 5 year life. The impact on the RAB is not significant.
For other assets, the asset base has been rolled forward as per accepted DORC practice using the asset's depreciable life.

GHD notes that assets that are fully depreciated, then revalued and reinstated in the asset base as at 30 June 2001, should not again be reinstated after a future valuation if they are fully depreciated. This matter is for future reference of the Commission.

8.4 Proposed Asset Base Roll Forward Schedule

Evaluation of the summary data provided for the roll forward by Transend has identified two modifications, viz:

- Capex CPI for the final 6 months as outlined in the Indexation section above
- Recommended change to treatment of land and easement acquisition costs.

Table 8.3 shows the schedule for the RAB as recommended by GHD as at 31 December 2003 and inclusive of the changes identified by GHD.

Table 8-3 GHD Regulatory Asset Base Roll Forward as at 31 December 2003

Item	Regulatory Asset Base at 31 December 2003 (Nominal $m)
Substations	249.6
Transmission lines and cables	220.6
Protection and Control	34.6
Refurbishments	8.8
Land and Easements	65.1
Other assets	18.9
Total	**597.6**

A build up of this roll forward from 30 June 2001 to 31 December 2003, by period, is shown in Table 8.4.

Table 8-4 Roll Forward Buildup from 30 June 2001 to 31 December 2003, by Period (Nominal $m).

Period	Details	Adjustments	Total
1 July 2001 – June 2002	**Opening Assets**		**521.6**
	Add Assets brought into Service	33.9	
	Less Depreciation	11.7	
	Less Disposals	4.0	
1 July 2002 – June 2003	**Opening Assets**		**539.8**
	Add Assets brought into Service	54.7	
	Less Depreciation	14.2	
	Less Disposals	3.5	

Period	Details	Adjustments	Total
1 July 2003 – 31 Dec 2003	**Opening Assets**		**576.7**
	Add Assets brought into Service	31.7	
	Less Depreciation	10.0	
	Less Disposals	.8	
31 Dec 2003	**Closing Assets**		**597.6**

A schedule showing the recommended detailed RAB roll forward will be provided to the Commission separately.

8.5 Future Roll-Forward During the Regulatory Period

Whilst beyond the scope of this report, GHD notes a modification to the treatment of depreciation of assets proposed under the formula for asset roll-forward during the RP.

In this second roll forward, Transend proposes that the assets are rolled up into 6 broad categories and then the RAB is depreciated over the average remaining economic lives of that asset category. The asset lives under the proposal are summarised in Table 8.5.

Table 8-5 Transend Proposed Asset Lives for Roll-Forward During the RP.

Asset Category	Depreciable Life, Yrs	Av. Remaining Economic Life
Transmission Lines and Cables	60	21.4
Transmission Substations	50	26.1
Protection and Control	15	8.6
Refurbishments	15	14.5
Other	N/A	10.8
Land and Easements	N/A	N/A

Review of the information from Transend reveals that:

- The full Land and Easements amount of $71.04m as at 31 Dec 2003, of which approximately $15m is land value with the remainder being acquisition costs, is only indexed and not depreciated.
- Transend has treated Refurbishments after 1 July 2003 separately and applied a class life of 15 years as noted in Appendix 3 of the Application.

The Commission may wish to consider these issues.

9. Service Standards and Performance Incentives

9.1 Introduction

The Application proposes a Performance Incentive (PI) Scheme for Transend which is based on:

- The Commission's framework for performance incentives,
- A report for the Commission - "Transmission Network Service Providers Service Standards" by Sinclair Knight Merz, November 2002,
- A report for Transend – "Transend Service Standards Project" by Transgrid, March 2003.

The proposed PI Scheme proposes four service indicators:

- Transmission circuit availability
- Transformer circuit availability
- Loss of supply event frequency index, comprising:
  - Number of events where loss of supply exceeds 0.1 system minutes
  - Number of events where loss of supply exceeds 2.0 system minutes

A summary of the PI Scheme proposal in the Application (Table A1 in Appendix 4) is provided in Table 9-1 below.

Table 9-1 Summary of Transend Proposal for Performance Incentive Scheme

Service Indicator	Measure	Maximum revenue at risk	Maximum penalty performance	Penalty trigger	Bonus trigger	Maximum bonus performance
S1- Transmission circuit availability	Percentage availability	0.25%	98.8%	<99.0%	>99.1%	99.3%
S2- Transformer circuit availability	Percentage availability	0.15%	98.8%	<99.0%	>99.1%	99.5%
S3- Loss of supply event frequency index (a)	Number of LOS events >0.1 system minutes.	0.2%	20 events	>16 events	<14 events	10 events
S4- Loss of supply event frequency index (b)	Number of LOS events >2.0 system minutes.	0.4%	5 events	>3 events	<2 events	0 events

The proposed scheme puts a total of 1% of revenue at risk, but is intended to be revenue neutral based on the past 4 years of performance.

Transend states that the proposed service indicator targets are challenging when the proposed extensive works program is implemented. Events triggered by other market network service providers including Basslink are proposed to be excluded.

9.2 Selection of Service Indicators

The selection of service indicators for the Transend PI Scheme is consistent with the proposals in the Commission report by SKM, with the exception of an indicator for outage duration. Review of Transend's performance indicates that performance in outage duration is likely to be volatile due to a small number of significant events, and hence may not be an appropriate indicator for a PI Scheme.

GHD thus concurs with Transend's selection of four service indicators for the scheme.

9.3 Historical Performance Comparison

Comparison of Transend's historical performance with the proposed PI scheme is provided in Table 9-2. It is noted that performance information is only available for the past four years, which is a limited period for determining trends and variability in indicators.

Table 9-2 Historical Performance Comparison with Proposed PI Scheme

Service Indicator	Historical Performance					
	1998-9	1999-0	2000-1	2001-2	PI Scheme [1]	
					Min	Max
Transmission Circuit Avail %	99.13	99.17	98.96	99.17	99.0	99.1
Transformer Circuit Avail %	98.47	98.70	99.17	99.13	99.0	99.1
Loss of Supply Event > 0.1 min	13	16	15	16	14	16
Loss of Supply Event > 2 min	1	4	3	1	2	3

Note 1. Transend proposed PI Scheme limits beyond which bonuses or penalties apply. See Table A1, Appendix 4 of Application.

Detailed analysis of the proposed PI Scheme, if applied over the historic performance set out in Table 9.2, indicates that Transend would have received bonuses on a net 8 occasions and penalties on a net 4 occasions. If applied over the RP to Transend's Application revenue, this would result in an average bonus to Transend of 0.045% of revenue per year, or about $50,000 per year.

It can thus be concluded that the proposed scheme would result in a nominal bonus to Transend if historical performance were repeated, albeit based on a very limited history. This does not provide for long term availability improvements (eg. in transformer circuit availability) resulting from the proposed increase in maintenance activity or relevant development and renewal Capex such as reactive support projects. Offsetting these improvements during the RP is the potential increase in planned outages resulting from the increased Capex and maintenance activity. Transend has stated that the four years of information available does not provide sufficient data to make a meaningful (or statistically sound) estimate of 'reliability improvements' directly resulting from this expenditure, and that a large data set over a long period of time is required before relationships between actions and outcomes can be assumed.

Further review of historical performance and reports indicates that:

- There is a lack of clarity in classifying the cause of outages, which may impede analysis and management of reliability improvements, and
- There is some scope for improvements in outage performance by addressing initiatives such as improved outage scheduling and coordination, overnight return to service of systems when multi-day outages occur, and performing in-service maintenance.

9.4 Summary of Findings

The selection of service indicators by Transend is considered appropriate.

In the absence of further information, GHD concludes that the proposed PI Scheme does not appear to be challenging when compared with past performance, albeit limited. If past performance is repeated, Transend is likely to receive a net nominal bonus over the RP, but this is not considered significant.

Recently completed maintenance projects may contribute to long term improvements in availability. New proposed Capex may improve long term availability of the system, while in the short term, the increased Capex and maintenance programs proposed will increase the need for planned outages and may have some adverse effect on equipment reliability and circuit availability performance. There is identified scope to improve service performance using improved work practices.

On balance, it could be expected that Transend could achieve an increased bonus over that estimated from historical performance, for the PI Scheme proposed in the Application.

9.5 Suggested Alternative Performance Incentive Scheme

An alternative suggested scheme which could remain revenue neutral on the basis of some allowance for reasonable improvements in performance due to investment, maintenance and improved practices, is outlined below in Table 9-3. The alternative has considered both the trigger levels and weightings. Suggested changes are shown in bold type.

Table 9-3 Suggested Performance Incentive Scheme

Service Indicator	Measure	Maximum revenue at risk	Maximum penalty performance	Penalty trigger	Bonus trigger	Maximum bonus performance
S1- Transmission circuit availability	Percentage availability	0.25%	**98.9%**	**<99.1%**	**>99.2%**	**99.4%**
S2- Transformer circuit availability	Percentage availability	0.15%	98.8%	<99.0%	>99.1%	99.5%
S3- Loss of supply event frequency index (a)	Number of LOS events >0.1 system minutes.	0.2%	20 events	>16 events	**<13 events**	**9 events**
S4- Loss of supply event frequency index (b)	Number of LOS events >2.0 system minutes.	0.4%	5 events	>3 events	<2 events	0 events

While not particularly challenging, the alternative scheme is considered more appropriate as a means of implementing a PI scheme in the absence of longer term performance data or any analysis of past performance improvements or future expectations by Transend.

10. Efficiency Bonus

Transend proposes in Section 3 of the Application that an Efficiency Bonus of some $1.5 million apply to the RP. The basis for this proposal is that Transend has increased its scope of work over the previous revenue period as a result of NEM entry activities, compliance with regulatory developments, and participation in various reviews and regulatory guidelines.

Costs of many additional activities (proposed by Transend as “catch-up” tasks, as well as new tasks relating to NEM entry, for example), have been built into the Application forecast Opex along with the ongoing costs of the previously identified increased scope activities (some of which are once-off).

GHD has provided a suggested Opex trend which includes allowances for new tasks undertaken by Transend. It appears unnecessary to compensate Transend further for preventing incurred costs which should properly be claimed under the previous revenue period, if indeed they are justified.

The basis on which an efficiency bonus is payable in addition to claimed Opex is thus difficult to assess.

Consequently, GHD cannot recommend the allowance of an efficiency bonus.

Appendix A

Glossary of Terms and Acronyms

Glossary of Terms and Acronyms

Acronym	Term
Commission	The Australian Competition and Consumer Commission
Transend	Transend Networks Pty. Ltd.
RP	Regulatory Period
Capex	Capital Expenditure
Opex	Operating Expenditure
AT	ACIL Tasman
NEM	National Electricity Market
KPI’s	Key Performance Indicators
TNSP	Transmission Network Service Provider
RAB	Regulatory Asset Base
PI	Performance Incentive
NEC	National Electricity Code
TPA	Trade Practices Act 1974
TEC	Tasmanian Electricity Code
ToR	Terms of Reference
HEC	Hydro Electric Commission
NEMMCO	National Electrical Market Management Company
OTTER	Office of The Tasmanian Energy Regulator
TWEM	Tasmanian Wholesale Energy Market
SKM	Sinclair Knight Mertz
ESAA	Electricity Supply Association of Australia
WACC	Weighted Average Cost of Capital
NIEIR	National Institute of Economic and Industrial Research
CBA	Capital Based Assessment

Appendix B

References

Appendix B Register of information provided to GHD and the Commission

No.	Document	Format	Date provided	Confidential
1	Map: *Tasmania's Electricity System 1999*	Hard copy	20 March (couriered)	No
2	*2002 Planning Statement,* System Controller, Transend	Hard copy	20 March (couriered)	No
3	Page 44, *Electricity Australia 2002,* Electricity Supply Association of Australia Limited, containing *Table 3.5: Technical indicators – transmission* and *Table 3.6: Personnel indicators – transmission*	Photocopy of relevant page	20 March (couriered)	No
4	*2002 Terminal Substation Ten Year Consumption and Maximum Demand Forecast,* Aurora Energy, February 2003	*ACCC info disk 1*	20 March (couriered)	Yes
5	*Tasmanian Electricity System Diagram*, TSD-OL-810-0001-004	*ACCC info disk 1*	20 March (couriered)	No
6	*Transend Networks – Business Risk Review Update,* KPMG, February 2001	Electronic copy	21 March (emailed)	Yes
7	*Benchmarking Transend's Cost Performance: Analysis and Evidence - April 2002,* Pacific Economics Group, April 2002	Electronic copy	21 March (emailed)	Yes
8	*Transend Development Plan – January 2004 to June 2009*, Transend Networks and Sinclair Knight Merz March 2003	Electronic copy	21 March (emailed)	Yes
9	*Policy Statement: Capitalisation*, Transend Networks, February 2003	Electronic copy	21 March (emailed)	Yes
10	*Application Asset Roll Fwd 1 July 2001 to 1 Jan 2004.xls*	Electronic copy	21 March (emailed)	Yes
11	*Application Forecast Capex.xls* (Overview of Capex projects)	Electronic	25 March (hardcopy to GHD) 27 March (emailed to GHD and ACCC)	Yes
12	Sample extract from asset register	Hard copy to GHD to determine their information needs	26 March (hard copy to GHD)	Yes
13	Capex – Two power point presentations: Process for determining Renewal Capex (*note: renewal numbers in final spreadsheet relate to Capex spend, not roll-in)* Development Capex	Electronic (plus presentations to GHD and ACCC)	25 March (emailed to ACCC, electronic copy to GHD)	Yes
14	Opex - Two power point presentations: Process for determining Opex for *Connections & Development* *Network*	Electronic (plus presentations to GHD)	26 March (electronic copy to GHD) 27 March (electronic copy to ACCC)	Yes

No.	Document	Format	Date provided	Confidential
15	*Revenue application overview* – One power point power point presentation	Electronic (plus presentations to GHD and ACCC)	11 March (presentation) 27 March (electronic copy to ACCC and GHD)	Yes
16	*Intermittent Generation in the National Electricity Market,* NEMMCO, March 2003	Electronic	27 March 2003	No
17	*Draft Transmission System Management Plan*, Transend Networks, March 2003	Hard copy	31 March 2003	Yes
18	*Transend Networks Pty Ltd Organisational Structure,* Transend Networks, 28 February 2003	Hard copy	1 April 2003	No
19	3 photocopied pages relating to Risdon substation 33kV connection project (from functional project specification and business case)	Hard copy	3 April 2003	Yes
20	4 photocopied pages relating to Norwood-Scottsdale-Derby project (from submission to RNPP, Transend north-east strategy document and Hydro Consulting report)	Hard copy	3 April 2003	Yes
21	2 photocopied pages relating to the Southern augmentation project (source: working files)	Hard copy	3 April 2003	Yes
22	1 photocopied page relating to the Reactive Support Program and costs (source: working files)	Hard copy	3 April 2003	Yes
23	*Transend Networks Annual Planning Review with Aurora Energy 2002*	Hard copy	3 April 2003	Yes
24	*Non-network projects* - historic and forecast Capex for projects classified as 'non-network'.	Hard copy	2 April 2003	Yes
25	110kV VT and coupling capacitor condition assessment report	Hard copy	2 April 2003	Yes
26	220 kV substation assets asset management plan	Hard copy	2 April 2003	Yes
27	110 kV circuit breaker condition assessment report	Hard copy	2 April 2003	Yes

No.	Document	Format	Date provided	Confidential
28	Copies of EHV circuit breakers, HV switchgear, Power Transformer renewal program with timing and drivers	Hard copy	3 April 2003	Yes
29	Copy of cost basis for substation redevelopment for Tarraleah project	Hard copy	3 April 2003	Yes
30	Copy of cost basis for Norwood Scottsdale and Derby	Hard copy	3 April 2003	Yes
31	Seven power point presentations – presented while GHD and ACCC were visiting Tasmania (31 March – 2 April) *030331 CEO intro* *030331 Network operating environment* *030331 Overview of NEM Entry costs* *030401 C&D Opex expenditure* *030401 Transmission operations expenditure_01* *030402 Benchmarking* *030402 Summing up*	Electronic (plus presentations to GHD and some to ACCC)	4 April 2003 (emailed)	Yes
32	*030404 Renewal Capital Profile 1998-2003.pdf* - a graphical profile of past renewal Capex	Electronic	3 April (hard copy) 4 April 2003 (emailed)	Yes
33	*Appendix 4 - Transmission Lines Expenditure Tables1.pdf* – extract from Transmission System Management Plan	Electronic	4 April 2003 (emailed)	Yes
34	*Appendix 3 - Substations Expenditure Tables.pdf*– extract from Transmission System Management Plan	Electronic	4 April 2003 (emailed)	Yes
35	Fax with pages 32, 33, 40 and 41 from the ESAA *Electricity Australia 2002* report and definition of operating cost per transmission unit.	Facsimile	4 April 2003 (faxed)	No
36	*040403 Benchmarks - opex v1.xls* (Transend's calculation of high level opex benchmarks adopted by the ACCC).	Electronic	7 April 2003 (emailed)	Yes
37	Package of information concerning NEM-entry issues: Project scope definition: Limit equations TWEM NEM entry 'Mudmaps' (overview of work streams and tasks under each) Preconditions to Tasmanian NEM entry Operational and Market information technology Tasmanian Power System, Operational and Market Communications Systems Wholesale Metering Steering Committee, Project Plan March 2003-04-07 System Security Capability Post NEM Entry	Bound hard copy	7 April 2003 (express post)	Yes

No.	Document	Format	Date provided	Confidential
	Electricity Supply Industry Amendment Bill 2003, Second Reading Speech			
38	*Tasmania's Energy Reform Framework, Entry to the National Electricity Market,* State Treasury	Hard copy	7 April 2003 (express post)	Yes
39	*Transmission System Management Plan* excerpts: *TSMP Appendices cover sheet.pdf* *Appendix 0 - Transmission System Management Process.pdf* (flow chart)	Electronic	7 April 2003 (emailed)	Yes
40	*Project Initiation process document:* document number TNM-GS-809-0406	Hard copy	3 April (hard copy)	Yes
41	Spreadsheet explaining CPI assumptions: *GHD Question 3.1 – CPI.xls*	Electronic	11 April 2003 (emailed)	No
42	*HASU_Report.pdf*	Electronic	11 April 2003 (emailed)	No
43	*Overview of Opex* (one page summary sheet)	Hard copy	1 April 2003	Yes
44	*030320 - MEMO - asset register review*	Electronic	20 March 2003 (emailed)	Yes
45	*030321 - MEMO - information sent 21 March*	Electronic	21 March 2003 (emailed)	Yes
46	*030327 - MEMO - information sent 27 March*	Electronic	27 March 2003 (emailed)	Yes
47	*030407 - MEMO- further appendix to TSMP*	Electronic	7 April 2003 (emailed)	Yes
48	*030411 - MEMO - information sent 11 April*	Electronic	11 April 2003 (emailed)	Yes
49	*Sinclair Knight Merz –Transend Networks Asset Valuation Reference Date 30 June 2001*	Hard copy	April 2003 to GHD May 2003 to ACCC	Yes
50	*DLV General Review Checklist 23-04-03 Transend.xls*	Electronic	30 April 2003 (emailed)	Yes
51	*Jap response.pdf*	Electronic	30 April 2003 (emailed)	Yes
52	*Reg Reporter ToR 2002.pdf*	Electronic	30 April 2003 (emailed)	Yes

No.	Document	Format	Date provided	Confidential
53	*Robert e-mail.pdf* (email outlining opex overhead allocation)	Electronic	30 April 2003 (emailed)	Yes
54	*Response to GHD Queries 02 May 20031.doc*	Electronic	2 May 2003 (emailed)	Yes
55	*Eco Depn calcs.xls*	Electronic	17 April 2003 (emailed)	Yes
56	*RAB 30 June 2001-Depn*	Electronic	17 April 2003 (emailed)	Yes
57	*CD cost changes.pdf*	Electronic	17 April 2003 (emailed)	Yes
58	*Nem Entry cost changes.pdf*	Electronic	17 April 2003 (emailed)	Yes
59	*Total Capex summary.xls*	Electronic	17 April 2003 (emailed)	Yes
60	*IT.pdf*	Electronic	17 April 2003 (emailed)	Yes
61	*Tend03-Riskreview-RO204.pdf*	Electronic	17 April 2003 (emailed)	Yes
62	*TEND03-KeyFinancialSystemsVisit1Final-R2904.pdf*	Electronic	17 April 2003 (emailed)	Yes
63	*TEND03-InsuranceReviewFollowUp-0603.pdf*	Electronic	17 April 2003 (emailed)	Yes
64	Spreadsheet detailing Non-network projects	Hard copy	16 April 2003	Yes
65	Spreadsheet outlining costs for *Preparation for NEM and Basslink* and Participation in the NEM	Hard copy	16 April 2003	Yes
66	Chart showing trend line between annual easement cost vs reliability	Hard copy	16 April 2003	Yes
67	*Bound document containing Appendices 3 to 11 of TSMP*	Hard copy	16 April 2003	Yes
68	*Series of spreadsheets showing changes in OCEO, F&B, Insurance, Legal and Contracts, Company secretary, MRG and HR costs*	Hard copy	April 2003	Yes
69	*030506 - MEMO - IDC*	Electronic	6 May 2003 (emailed)	No
70	Email to Garry Taylor: *Re: Interest During Construction*	Email text	6 May 2003 (email)	No

No.	Document	Format	Date provided	Confidential
71	*Hydro response to southern transmission.pdf*	Electronic	8 May 2003 (emailed)	No
72	*030516 - MEMO - response to GHD questions 16 May*	Electronic	16 May 2003 (emailed)	Yes
73	*030519 - MEMO - RNPP process questions.doc*	Electronic	19 May 2003 (emailed)	No
74	*030519 - MEMO - further GHD questions.doc*	Electronic	19 May 2003 (emailed)	Yes
75	*030520 - Historical Forecast Capex.xls* and explanatory email	Electronic	20 May (emailed)	No
76	*030521 - MEMO - insurance.doc*	Electronic	21 May (emailed)	Yes
77	*Transend/Aurora - 04A Open Book Review* - KPMG	Hard copy	16 April 2003	Yes
78	*Risdon Substation redevelopment Agenda Item 6C to Board* 28 April 2000	Hard copy	16 April 2003	Yes
79	Hard copy of email from James Olivier 28 May 2002 - Comments re SKM reliability document	Hard copy	16 April 2003	Yes
80	Hard copy of email from Hendrik Kremer 27 May 2002 - Security System Report	Hard copy	16 April 2003	Yes
81	Hard copy of email from Greg Jones 30 May 2002 - Draft Letter on SKM Security Criteria	Hard copy	16 April 2003	Yes
82	*Transend Service Standards Project March 2003 -* Transgrid	Hard copy	16 April 2003	Yes
83	*Transmission System Performance Report for 2001-2002* to Tasmanian Energy Regulator	Hard copy	16 April 2003	No
84	*Transmission System Performance Report for 2000-2001* to Tasmanian Energy Regulator	Hard copy	16 April 2003	No
85	*Easement Management Plan* Issue 1.0 April 2003	Hard copy	16 April 2003	Yes
86	*Asset Management Plan - Trans Line Foundations*. Issue 0.1 March 2003	Hard copy	16 April 2003	Yes
87	*Asset Management Plan - Insulator String Assemblies* Issue 0.1 March 2003	Hard copy	16 April 2003	Yes
88	*Asset Management Plan - Conductor Assemblies* Issue 0.1 March 2003	Hard copy	16 April 2003	Yes

No.	Document	Format	Date provided	Confidential
89	*Asset Management Plan - Support Assemblies* Issue 0.1 March 2003	Hard copy	16 April 2003	Yes
90	*Project Management Plan Checklist* TNM-GS-809-0038-001	Hard copy	16 April 2003	Yes
91	Contents Page of *Technology & Standards Group* Volume 1 & 2.	Hard copy	16 April 2003	Yes
92	*030523 - MEMO - GHD q14 re opex.doc*	Electronic	23 May 2003 (emailed)	Yes
94	*Breakdown of Transmission operations.xls* and explanatory email	Electronic	21 May 2003 (emailed)	Yes
93	*030523 - MEMO - AMIS.doc*	Electronic	23 May 2003 (emailed)	No
95	*030523 - Hydro P&T price increase claim.xls*	Electronic	23 May 2003 (emailed)	Yes
96	*030523 - Historical & Forecast Opex.xls* and explanatory email	Electronic	23 May 2003 (emailed)	No
97	*030513 – Development Substation Cost Estimates.xls*	Electronic		Yes
98	*030513 – MEMO – Substation renewal expenditure1.doc*	Electronic	13 May 2003 (emailed)	Yes
99	*030602 - MEMO - opex and service standards.doc*	Electronic	2 June 2003 (emailed)	No
100	*030602 - submission summary_29 May 03.doc* and explanatory email	Electronic	2 June 2003 (emailed)	Yes
101	Email titled *RE: Response to your questions dated 30 May.*	Electronic	2 June 2003 (emailed)	No
102	*030603 - MEMO - Grid support.doc*	Electronic	3 June 2003 (emailed)	Yes
103	*Late Entry – details TBA*			
104	*Late Entry – details TBA*			
105	*Late Entry – details TBA*			

Updated: Bess Ramsay   Complete as at: 3.55 pm 3 June 2003

Appendix C

ACIL Tasman
Independent Load Forecast

Confidential

Forecast Load and Generation for Tasmania

Prepared for ACCC

April 2003

ACIL Tasman

Economics Policy Strategy

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Contents

Boxes, figures, tables and charts

1 Load and Generation Forecasts

1.1 Introduction

This section of the report presents an independent forecast of Tasmanian electricity requirements for annual energy and peak demand prepared by ACIL Tasman (AT). This overall independent load forecast is compared with the forecast used by Transend in its Revenue Cap Application to the ACCC for the period 1 January 2004 to 30 June 2009.

Transend has based the assessment of its future capital expenditure needs in its Revenue Cap Application to ACCC on a report entitled, Transend Development Plan January 2004 to June 2009 prepared jointly by Transend and Sinclair Knight Merz (SKM) in March 2002. These capital expenditure needs have been based on the results of load flow modelling where forecasts of substation loads generation pattern are critical inputs.

The load forecasts used in the March 2003 Transend Development Plan, developed by SKM, are essentially exponential growth projections taking into account a variety of factors including past trends in electricity usage, economic and population growth, consideration of major industrial loads and the potential impacts of Basslink and the introduction of natural gas. The SKM forecasts are compares with other forecasts including those prepared by Aurora Energy and for Transend and ESAA by NIEIR.

The output of generators at system peak is also an important determining factor in Transend's future capital expenditure needs. The assumptions regarding generation patterns and in particular the assumed operation and loading of Basslink are examined and compared with results from the ACIL Tasman (AT) model of the National Electricity Market (NEM) (*PowerMark)* *PowerMark* provides a hourly simulation of the NEM over a ten year period and results include hourly flows on interconnectors and hourly dispatch from individual power stations in the NEM.

1.2 Load Forecast

The load forecast undertaken by ACIL Tasman is based on an examination of past trends annual energy and peak demands in Tasmania and underlying factors including economic growth, population growth and household formation, comparative energy prices, and major developments such as Basslink and availability of gas.

In deriving the overall load forecast ACIL Tasman went through the following steps:

- Forecast key underlying economic and demographic variables taking into account past trends and any major changes to underlying drivers such as the introduction of natural gas which may have potential to alter past trends;
- Forecast annual sales of electricity in Tasmania by key market segment taking into account past trends and changes to the underlying drivers such as the introduction of natural gas;
- Examine the key relationships between the underlying economic and demographic variables and electricity sales by key market segments to ensure consistency between the electricity sales forecast and the underlying variables.
- Apply an estimate of transmission and distribution losses to the sales forecast to obtain forecasts of annual energy sent out from power stations to the Transend transmission system;
- Using past trends in regional energy by major market segment, as available in Aurora Energy forecast, develop a regional sales forecast taking into account the possible changes to regional growth due to changes drivers such as the introduction of natural gas and ensure which is consistent with the overall results;
- Forecast peak demand for electricity in Tasmania taking into account past trends but ensuring that rends in load factor are consistent with those observed in the past; and
- Develop a peak demand forecast (both MW and MVA) by Transend terminal substation taking into account the regional energy forecast and overall peak demand forecast by applying coincidence factors; and
- Compare these forecasts with those prepared by NIEIR for TransEnd and ESAA, Aurora Energy and SKM.

1.2.1 Underlying Factors

Forecasts of the main underlying factors were mainly based on past trends adjusted where necessary to address any expected changes to the underlying drivers in particular the introduction of natural gas to Tasmania.

Economic Growth

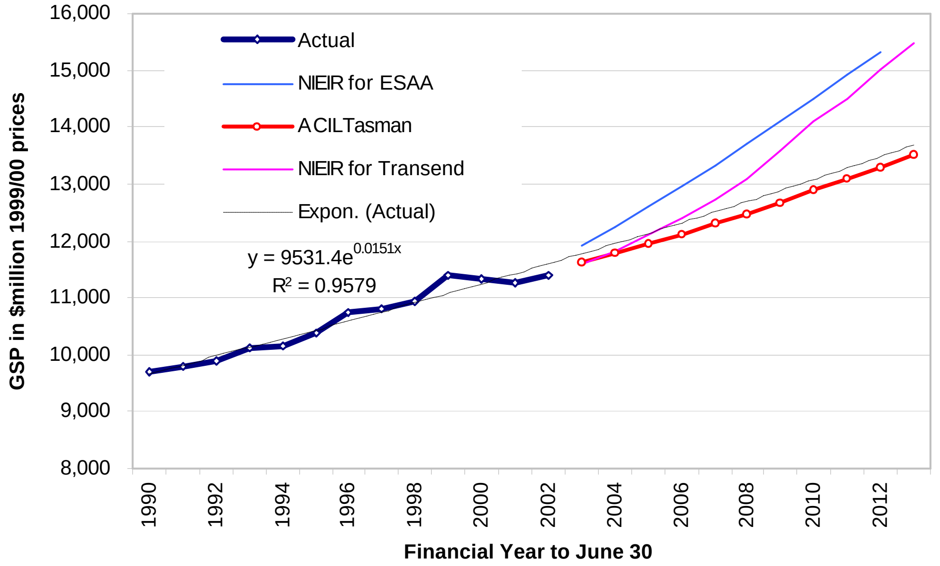
The past economic activity as measured by Gross State Product (GSP) and the median ACIL Tasman Forecast is shown in Figure 1. The long term exponential growth trend through historic data since 1989/90 shows an average annual growth of 1.5% per annum. The average annual growth in the ACIL forecast is also 1.5% with growth slightly higher at the end of the 10 year forecast due to the anticipated positive effect of natural gas. The positive effect natural gas on economic growth is expected to be only minimal with gas intensive loads more likely to locate in Victoria or Western Australia where gas prices are noticeably lower than in Tasmania. However it is expected that it will at least provide sufficient stimulus so as to balance the fact that Tasmania no longer has the low cost hydro generation capacity to continue to attract large electrical intensive loads as it has in past years.

The only other published forecast of GSP are by NIEIR for ESAA and Transend and these forecasts show an appreciable increase in GSP growth because of the introduction of natural gas although this been revised downwards in the more recent forecast for Transend because of an expected delay in gas reticulation in the state. ACIL Tasman considers the NIEIR forecast to be somewhat optimistic and does not seem to take into account the relatively higher costs of gas in Tasmania compared with other states, such as Western Australia, where the introduction of gas has been stimulatory to economic activity. Furthermore the Western Australian outcome was also largely driven by the availability of significant undeveloped mineral resources.

The ACIL Tasman view is supported by the following statement in the Aurora Energy 2002 Terminal Substation Ten Year Consumption and Demand Forecast report:

> It has to be noted that the consultants consider NIEIR medium economic growth rate forecast developed for Transend's 2001/02 System Control Annual Planning Report quite bullish and highly improbable.

Figure 1 **Actual and Forecast Economic Activity in Tasmania ($1999/00)**



Data source: Historic data from ABS

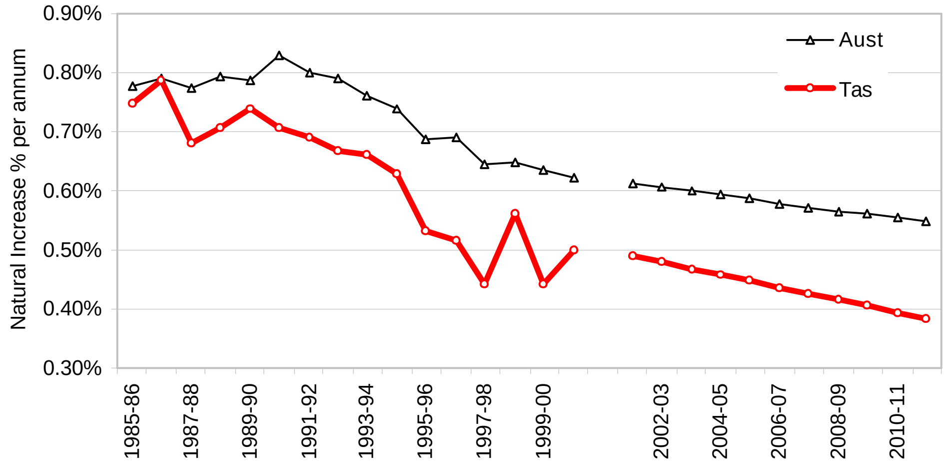
Population Forecast

Population growth is an important element in determining household formation and has a direct influence on level economic activity.

Population growth has three components, natural increase, net overseas migration and net interstate migration.

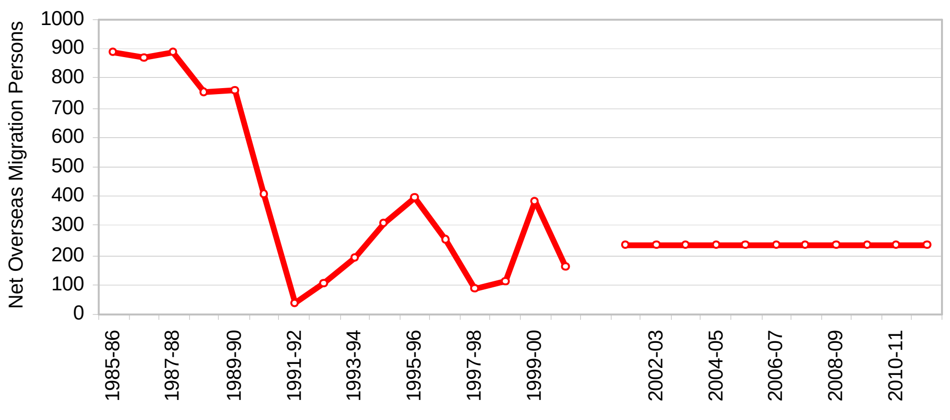
The trend in natural increase in Tasmania's population compared with Australia and the ACIL Tasman forecast is shown in Figure 2. The natural increase in Tasmania is less than Australia as a whole and has declines significantly over the past 15 years. ACIL Tasman expects this downward trend to continue but at a reduced rate. The main factors behind the decline in natural increase is the trend towards smaller families and the lower natural increase in Tasmania is mainly associated with the age profile of the population.

Figure 2 **Forecast of Natural Increase in Tasmania's Population**



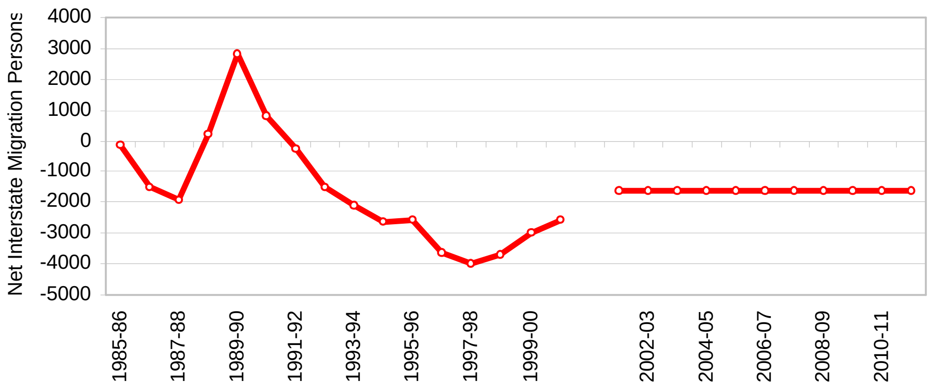
The net overseas migration to Tasmania is slightly positive as shown in Figure 3. ACIL Tasman is expecting a continued small annual increase in net overseas migration over the forecast period.

Figure 3 **Forecast of Net Overseas Migration to Tasmania**



The net interstate migration to Tasmania has been generally negative over the past 15 years (see Figure 4) and ACIL Tasman expects this trend to continue over the forecast period with which is consistent with economic growth somewhat less than for the nation as a whole.

Figure 4 **Forecast of Net Interstate Migration to Tasmania**



Overall population growth is expected to be slightly positive over the forecast period with the positive effects of natural increase and net overseas migration just offsetting the loss of persons to interstate. This is illustrated in Figure 5.

Figure 5 **Forecast Population Growth in Tasmania**

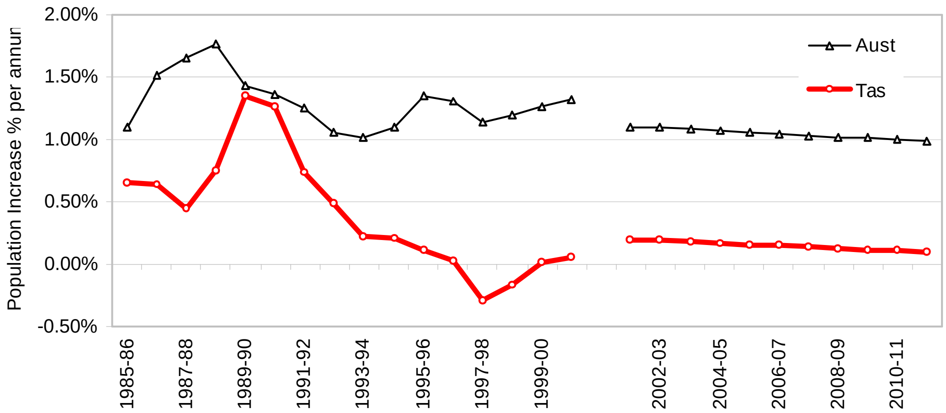
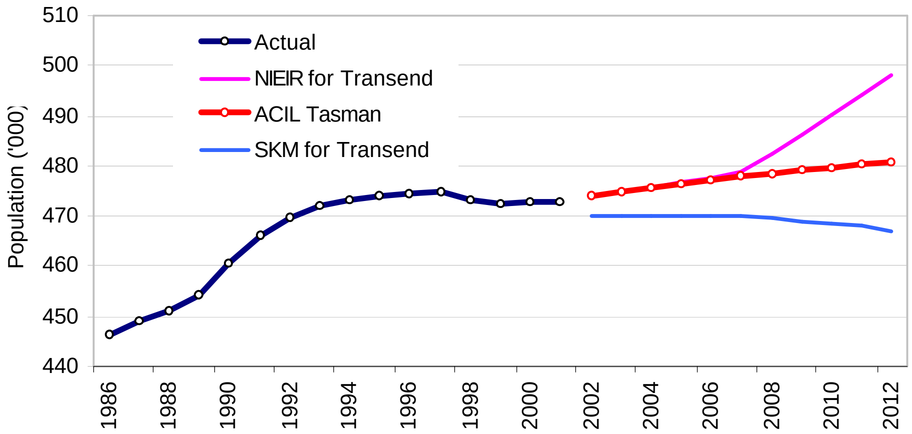


Figure 6 compares the ACIL Tasman forecast of population growth with the forecast prepared by NIEIR for Transend and that developed for the Transend forecast by SKM. The noticeably higher population forecast by NIEIR is consistent with the much higher economic growth and is regarded as optimistic as is the economic outlook.

Figure 6 **Comparison of Population Forecasts**

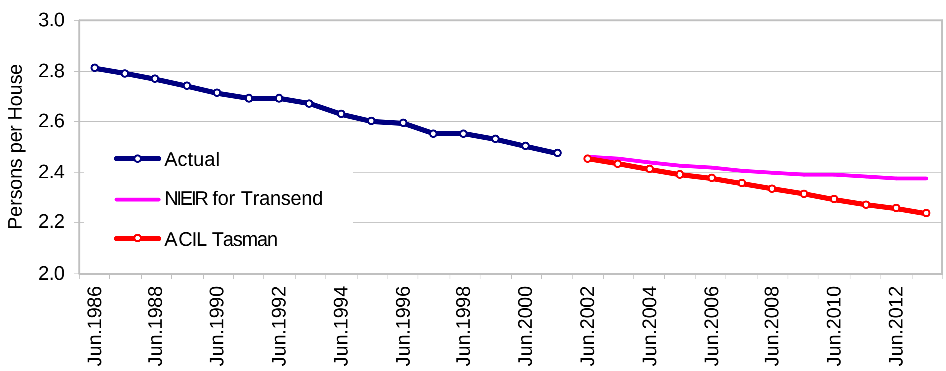


Household Formation

Household formation is an important driver for growth in the residential electricity requirement. Household numbers are growing a higher rate than population because the number of persons per household is dropping in line with the reduction in family size.

The number of persons per household is declining in all states and shown for Tasmania in Figure 7. ACIL Tasman expects the number of persons to continue to decline from the current level if 2.48 to 2.24 by 2012. This compares with the NIEIR forecast for Transend which shows the number of persons per household tending to stabilise at just under 2.4.

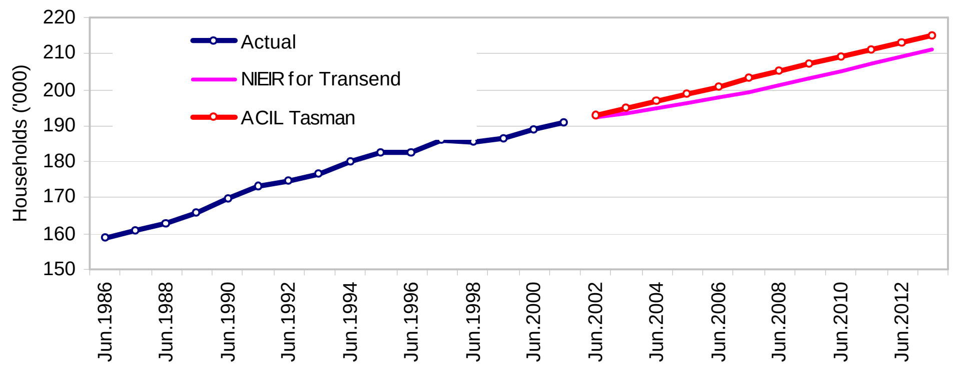
Figure 7 **Forecast Number of Persons per Household in Tasmania**



By dividing the population by the number of persons per household provides an estimate of the number of households and this is shown in Figure 8. The ACIL Tasman forecast is for an increase in households in Tasmania from

191,000 currently to around 215,000 by June 2013. The NIEIR forecast is for a slightly lower growth to around 211,ooo by 2013. The reason that the ACIL Tasman forecast of household numbers is higher than the NIEIR forecast, is that the higher population growth forecast by NIEIR is more than offset by the much slower decline in persons per household.

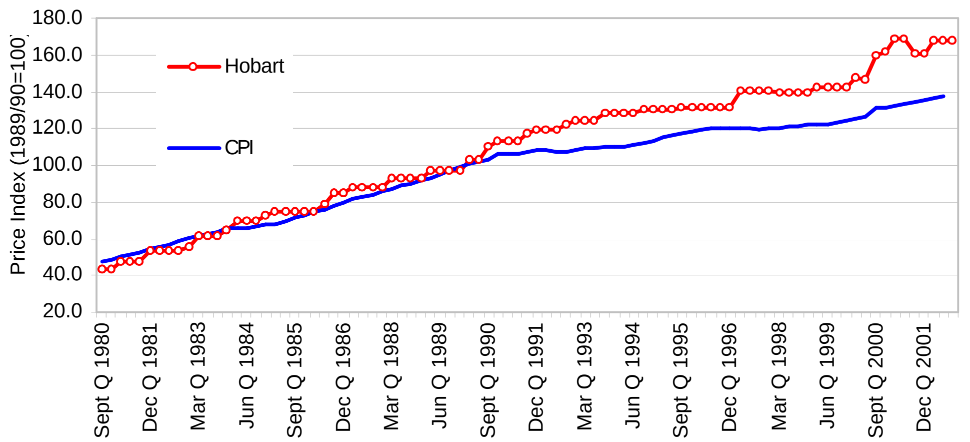
Figure 8 **Forecast of Household numbers in Tasmania**



Past trends in Electricity and Gas Prices

The price of electricity in Tasmanian residential sector has increased more than CPI during the nineties as shown in Figure 9. This may be partly the reason for the stalled growth in this segment of the market over recent years.

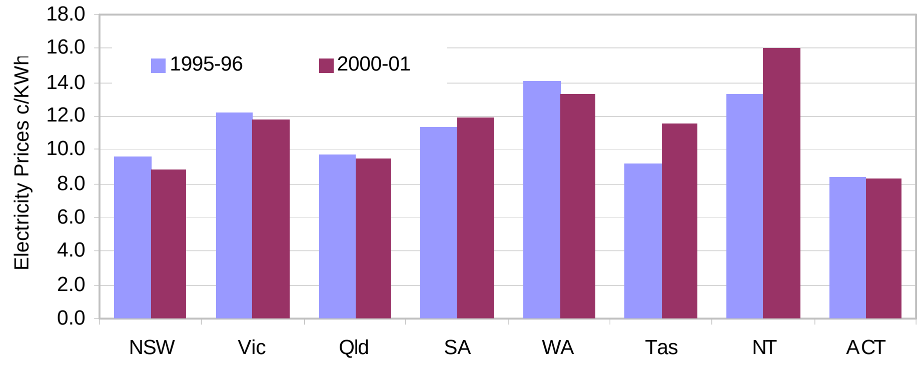
Figure 9 **Price Index for Residential Electricity in Hobart**



Data Source: ABS

According to the ESAA, between 1995/96 and 2000/01, the residential electricity prices in Tasmania have increased from among the lowest at 9.14c/KWh to be in the mid range at 11.54c/KWh. The residential prices in the three largest states all declined during this period. This is shown in Figure 10.

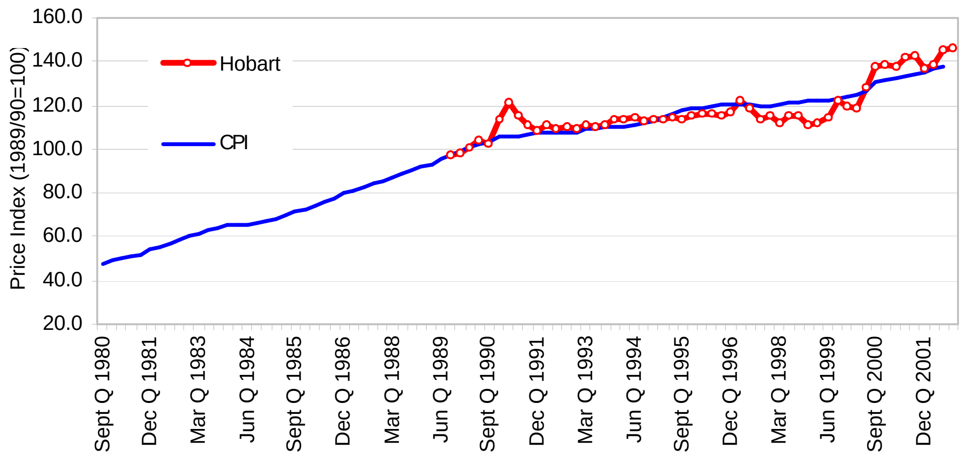
Figure 10 **Residential Electricity Prices by State in 1995/96 and 2000/01**



Data source: ESAA

The price for gas and other fuels in Hobart's residential sector has tended to track CPI as shown in Figure 11.

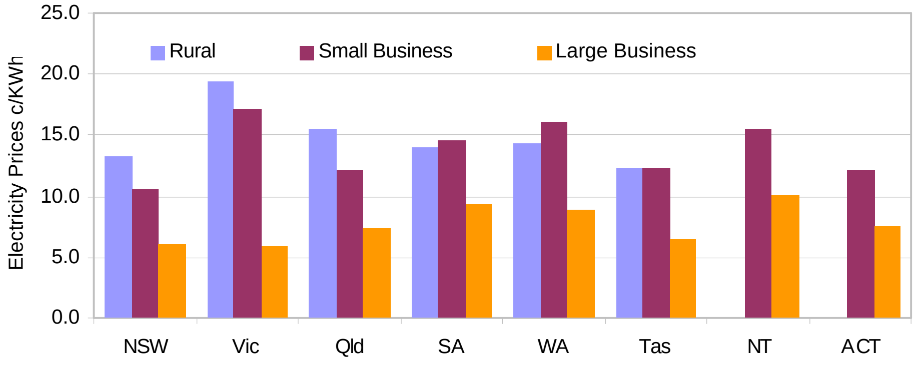
Figure 11 **Price Index for Residential Gas and Other Fuels in Hobart**



Data Source: ABS

Electricity prices for small business, large business and rural users in Tasmania are close to the lowest in Australia as shown in Figure 12. This suggests that electricity price would if anything be stimulatory for business to locate or expand in Tasmania.

Figure 12 **Business and Rural Electricity Prices by State 2000/01**



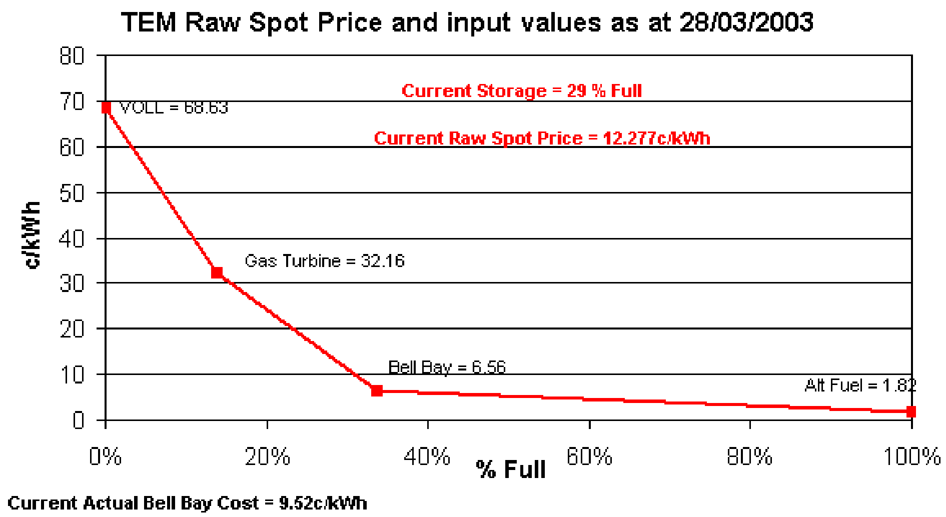
Data source: ESAA

Electricity Price Outlook

Electricity prices in Tasmania are forecast to continue to decline marginally in real terms in the period to the commencement of the electricity market in 2005 when wholesale electricity prices will be largely be a function of the supply demand balance in the NEM and the amount of water in the Tasmanian hydro dams.

Hydro Tasmania calculate a notional spot price for electricity in Tasmania calculated on the basis of how full the water storage are and the cost of alternative generation. The notional spot price on 28 March 2003 was 12.277c/KWh (or $122.77/MWh) with water storages only 29% full as shown in Figure 13. This is a very high price compared with those currently being experienced in the in the NEM.

Figure 13 **Hydro Tasmania's Spot price for 28 March 2003**

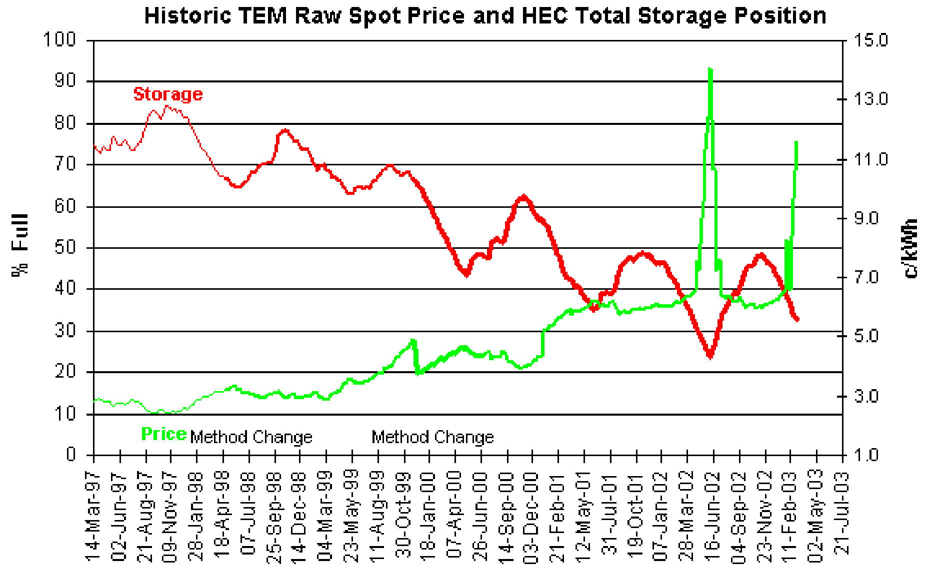


Data source: Hydro Tasmania

The trend in the Hydro Tasmania's spot price and percentage full for storages is shown in Figure 14. It shows that when storages are close to full then the spot price will be less than 2.0c/KWh (or $20.00/MWh) but that as the percentage full drops the Hydro Tasmania's spot price escalates and has been consistently above $50.00/MWh since the beginning of 2001 with storages consistently below 50% full.

These Tasmanian spot prices are considerably higher than the NEM pool price over this period and suggest that joining the NEM will mean that wholesale prices in Tasmania will be noticeably less than the current spot price when storages are less than 50% full. However NEM pool prices are likely to be above the Tasmanian spot price when storages are above 70% full. ACIL Tasman detailed modelling of the NEM suggests that beyond 2005 pool prices will tend to be in the $30 to 40/MWh range providing scope for lower Tasmanian spot prices generally. With more stable and generally lower spot prices we expect that electricity prices will continue to decline in real terms to the end of the 10 year forecast period.

Figure 14 **Hydro Tasmania's Spot Price History and Storage Position**



Data source: Hydro Tasmania

Gas Price Outlook

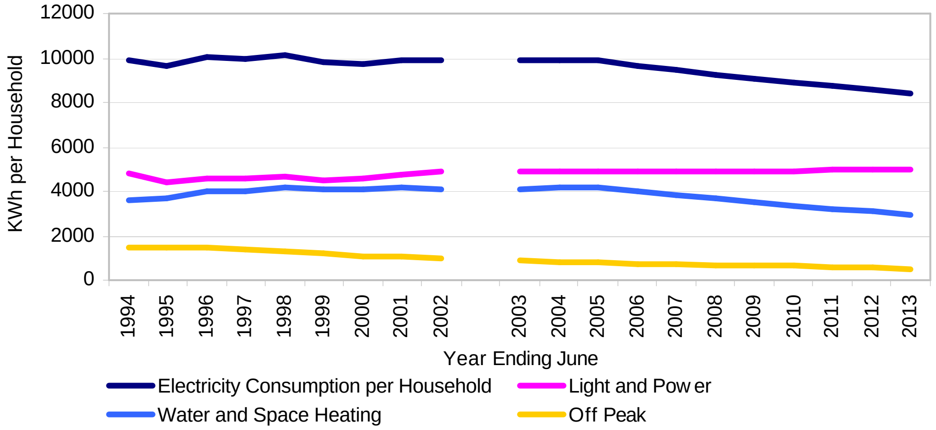
The price of gas in Tasmania will follow similar trends to gas prices in Victoria. Field prices are forecast to escalate with CPI each January while pipeline tariffs are forecast to increase at 80% of CPI.

1.2.2 Electricity Sales Forecast for Tasmania

Residential Sector

The domestic energy forecast is based on a continuation a continuation of the trends in consumption per household for light and power and off peak tariff types by an erosion of the heating tariffs assuming 60% of heating appliance replacements are replaced by gas appliances in areas assumed to be reticulated with gas from 2005 onwards. This results in an forecast average reduction in electricity used per household for space and water heating beyond 2005 of around 4.0% per annum compared with historic growth of 2.1% per annum in the period since 1994. The forecast for consumption per household by tariff type is shown in Figure 15.

Figure 15 **Forecast of Consumption per Household by Tariff Type**



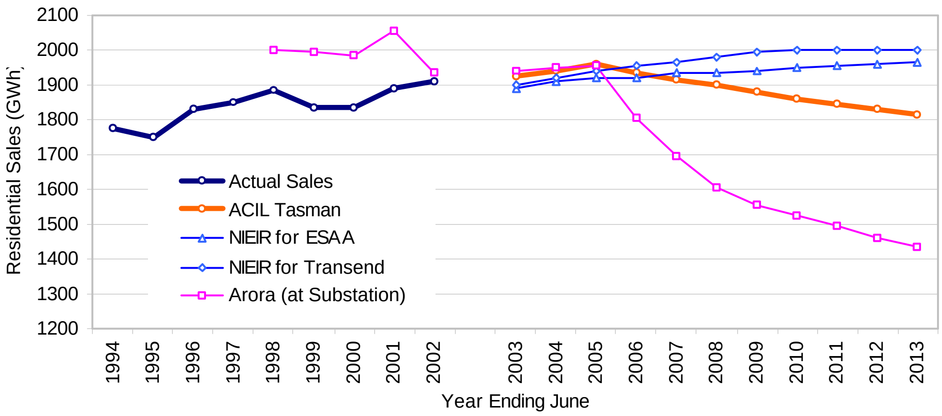
a this is a reference note

Note:

Data source: Electricity consumption from Aurora Annual reports and household numbers from ABS

Taking the forecast consumption per household and multiplying by the number of households gives the forecast of residential consumption as shown in Figure 16. The forecasts by others are included for comparison. The decline in residential energy at the substations as in the Aurora substation forecast in 2001/02 (ie domestic plus hydro heat and hot water) seems inconsistent with the residential sales to customers (ie domestic light and power plus hydro heat and hot water plus off- peak) published in the Aurora annual report.

Figure 16 **Forecast of Residential Electricity Consumption**



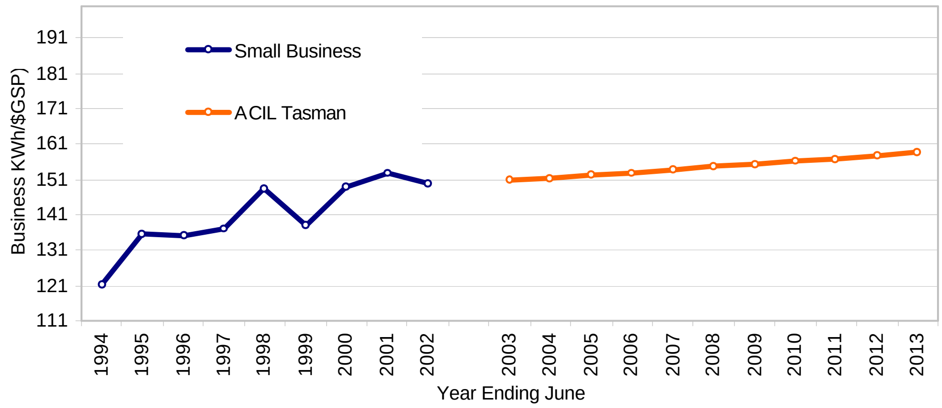
Data source: Actuals from Aurora Annual Reports and Substation Forecast Report

Other Tariff Customers (small business and farm)

The other tariff customers include small business and farm but do not include the 16 major industrial customers which have individual electricity supply arrangements.

The relationship between electricity consumption by business and economic activity in Tasmania and the ACIL Tasman forecast is shown in Figure 17. The forecast is for considerably lower growth in electrical intensity in the small business and farm sector mainly because gas is expected to be the preferred energy source for some applications, particularly space heating, which currently use electricity.

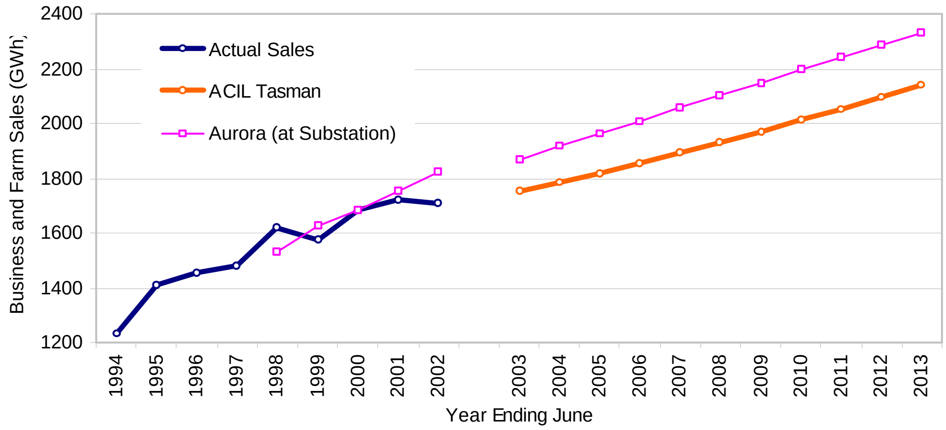
Figure 17 **Forecast of Electricity Intensity in Business Sector in Tasmania (KWh/$GSP)**



Data source: Actuals derived from electricity sales in the Aurora annual Report dvided by ABS estimates of gross state product.

Multiplying the forecast of GSP by the electrical intensity gives a forecast of electricity sales to small business and farm in Tasmania as shown in Figure 18. The ACIL Tasman forecast for business and farm sales of 2.1% which is 0.4% above economic growth but less than the 2.2% growth shown in the substation forecast for Aurora. These forecast growth rates compare with an average of 4.2% per annum over the eight years since 1993/94. The Aurora substation forecast has assumed that the introduction of natural gas will have no impact on electricity use in the small business and farm sector whereas the ACIL Tasman forecasts incorporates an allowance for loss of heating loads to gas in this sector. The main difference between the two forecasts is the distribution losses which are included in the Aurora substation forecast but not in the ACIL Tasman sales forecast which is at the customer terminal.

Figure 18 **Forecast of Electricity Sales to Other Tariff Customers (GWh)**

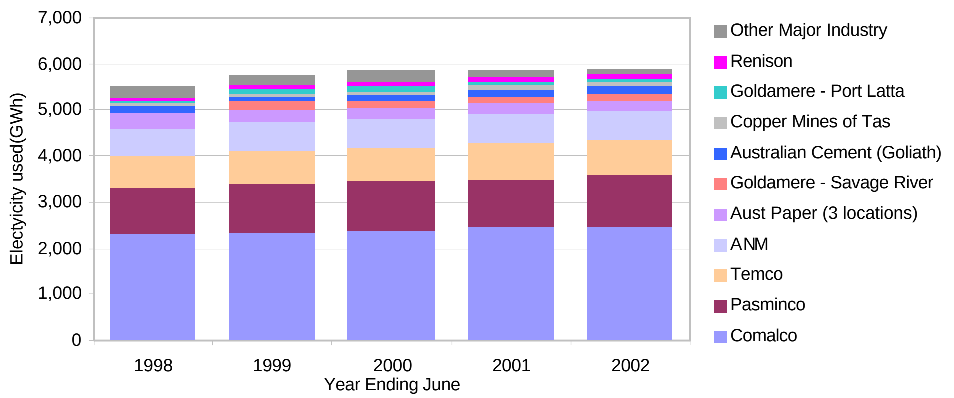


Data source: Actuals from Aurora Annual Reports and Substation Forecast Report

Major Industrial Customers

Electricity use by the 16 major industrial users in 2001/02 was 5902GWh or 62% of Tasmania's total electricity sales for that year. Furthermore, 5121GWh, or 87%, of sales to major industrial customers were to just five customers; Comalco, Pasminco, ANM, Temco and Australian Paper. Recent trends in electricity sales to major customers is are shown in Figure 19.

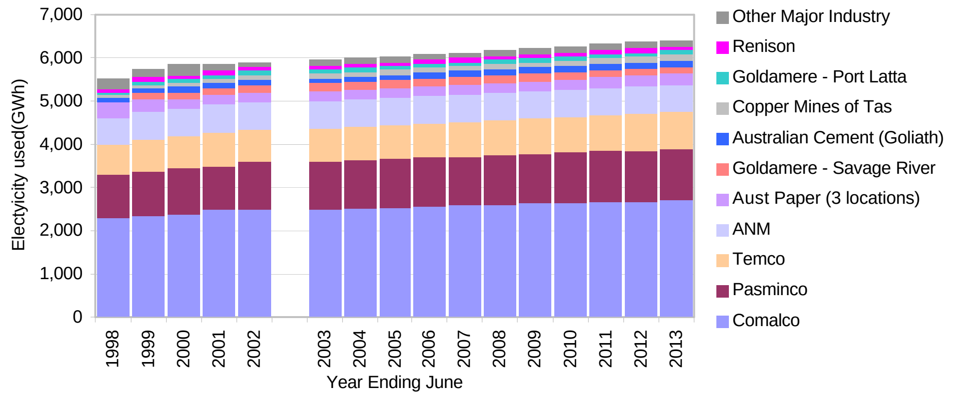
Figure 19 **Electricity sales to Major Industrial Customers in**



Data source: Aurora Substation Forecast Report

The future electricity sales to major customers depends on the availability of sufficient quantities of low priced electricity in Tasmania and the opportunities for further natural resource developments. ACIL Tasman has not been able to identify any new electrically intensive major new industrial loads in the immediate future in Tasmania. However electricity sales to existing major industrial customers has grown steadily in recent years and there is no reason to expect that this trend will not continue. On this basis, ACIL Tasman has forecast overall electricity sales to major industrial customer to increase at around 0.75% per annum over the forecast period compared with 1.7% per annum growth overall in the 8 years since 1993/94. During this time the growth includes the commencement of the Goldamere operations at Savage River and Port Latta whereas no major new loads are explicitly included in the ACIL Tasman forecast. The forecast of major loads is shown in Figure 20.

Figure 20 **Forecast of Electricity Sales to Major Industrial Customers**



Data source: Past data from Aurora Substation Forecast Report and forecast by ACIL Tasman

Overall Electricity Sales Forecast for Tasmania

Adding residential, other tariff and major industrial provides a forecast of overall sales in Tasmania as shown in Table 1. The overall forecast growth in electricity sales of 0.7% per annum is somewhat less than the average 1.9% per annum recorded since 1994. This is due mainly to the influence of the introduction of natural gas, particularly on electricity used in space and water heating, and the fact that no new major industrial loads are included in the forecast.

The growth in economic activity, population and household numbers follow similar trends to those observed in the recent past and are not expected to be stimulated noticeably by the introduction of natural gas.

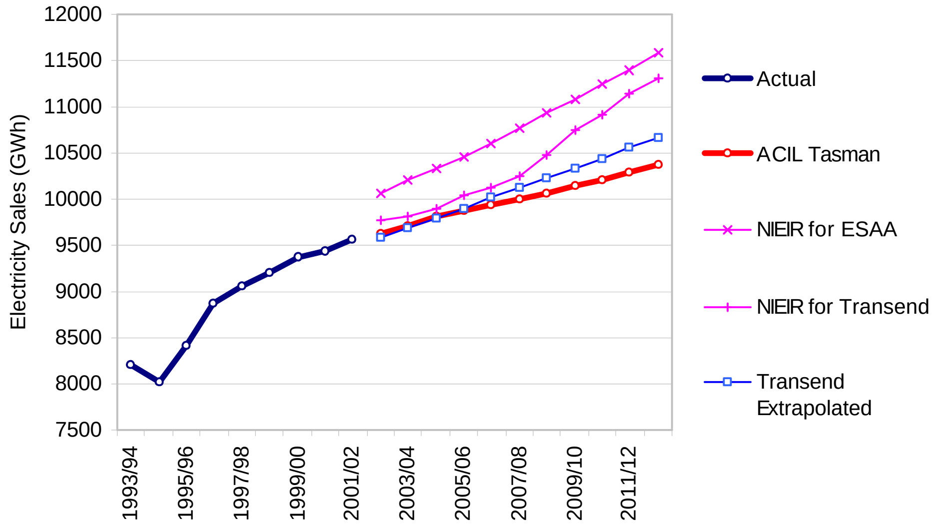
Table 1 **Forecast of Total Electricity Sales in Tasmania (GWh)**

Financial Year	Residential	Other Tariff (Small Business and Farm)	Major Industrial	Total Sales
1993/94	1773	1232	5196	8201
1994/95	1750	1410	4866	8027
1995/96	1828	1454	5134	8416
1996/97	1849	1482	5551	8882
1997/98	1887	1619	5556	9063
1998/99	1837	1574	5795	9205
1999/00	1837	1685	5847	9369
2000/01	1889	1721	5834	9444
2001/02	1912	1709	5936	9557
2002/03	1924	1750	5946	9621
2003/04	1941	1784	5991	9716
2004/05	1959	1818	6037	9813
2005/06	1937	1854	6083	9874
2006/07	1917	1891	6129	9937
2007/08	1898	1929	6175	10002
2008/09	1879	1970	6222	10072
2009/10	1862	2012	6269	10143
2010/11	1846	2054	6317	10217
2011/12	1830	2097	6365	10292
2012/13	1816	2141	6413	10370
Average Annual Growth Rates				
Historic	0.9%	4.2%	1.7%	1.9%
Forecast	-0.5%	2.1%	0.7%	0.7%

Source: Past data from Aurora Annual Reports Forecast by ACIL Tasman

ACIL Tasman forecast is less than either the NIEIR econometric forecast for Transend which anticipated a significant economic stimulus from gas and the Transend extrapolated forecast which assumes that the introduction of gas has no affect. The SKM forecast for Transend and the Aurora forecast did not provide sales forecasts. The comparison of the various forecasts electricity sales overall is shown in Figure 21.

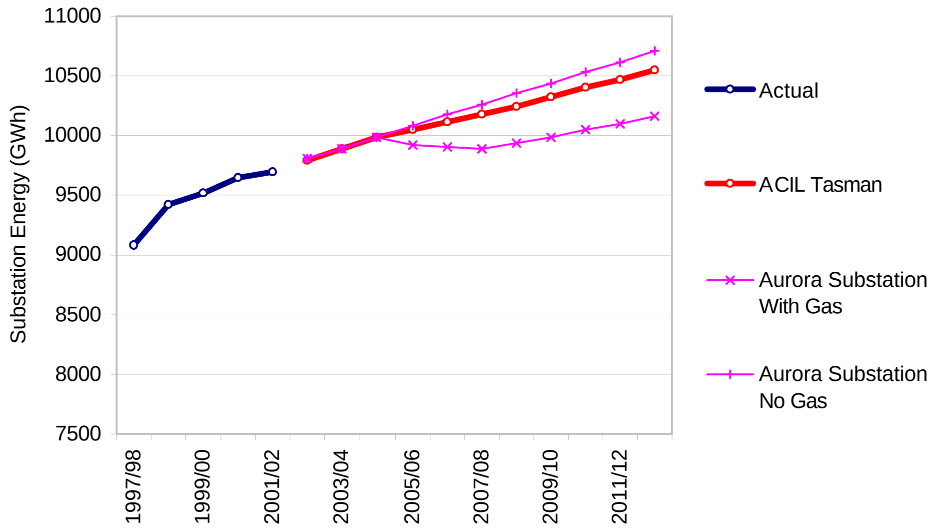
Figure 21 **ACIL Tasman Forecast of Electricity Sales Compared with Others**



1.2.3 Forecast of Energy at Substations.

The forecast of energy at substations includes the distribution losses estimated to average around 4.4% for tariff customers and zero for major industrial customers. Figure 22 shows a comparison between the ACIL Tasman forecast of energy at substations and the Aurora substations forecast. The ACIL Tasman forecast is closer to the Aurora substation forecast without gas even though the ACIL Tasman forecast includes a negative allowance for the introduction of natural gas.

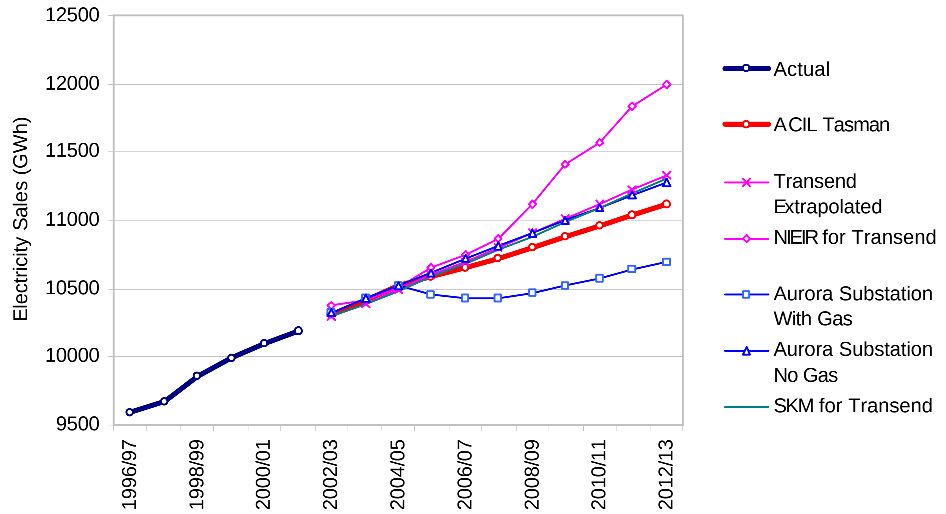
Figure 22 **Forecast of Energy at Substations**



1.2.4 Forecast of Generated Energy

The generated energy includes power station auxiliary losses (these have bees assumed at zero for Tasmania's hydro stations), main transmission losses (these have tended to average around 5.1% of energy generated in Tasmania) and distribution losses (these have averaged around 1.6% of the energy at the substations). There are several forecasts of overall energy generated in Tasmania which are presented in Figure 23. As can be seen from three forecasts, the Transend extrapolated, the Aurora substation without gas and the SKM for Transend are very similar, all have growth close to 1.0%. The ACIL Tasman forecast with an average growth lies below these forecasts but above the Aurora substation with gas. The NIEIR econometric forecast for Transend is significantly above all other forecasts particularly in the latter years of the forecast.

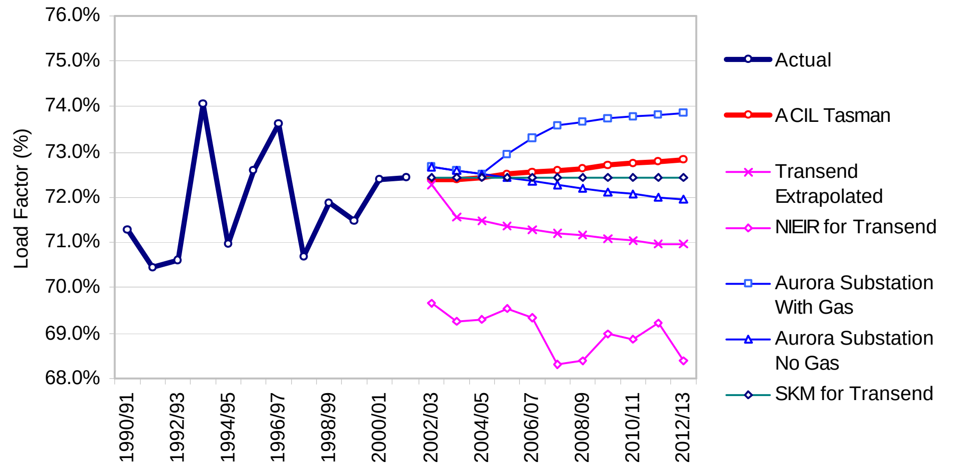
Figure 23 **Forecasts of Generated Energy in Tasmania**



1.2.5 Forecast of Generated Peak Demand (without Basslink)

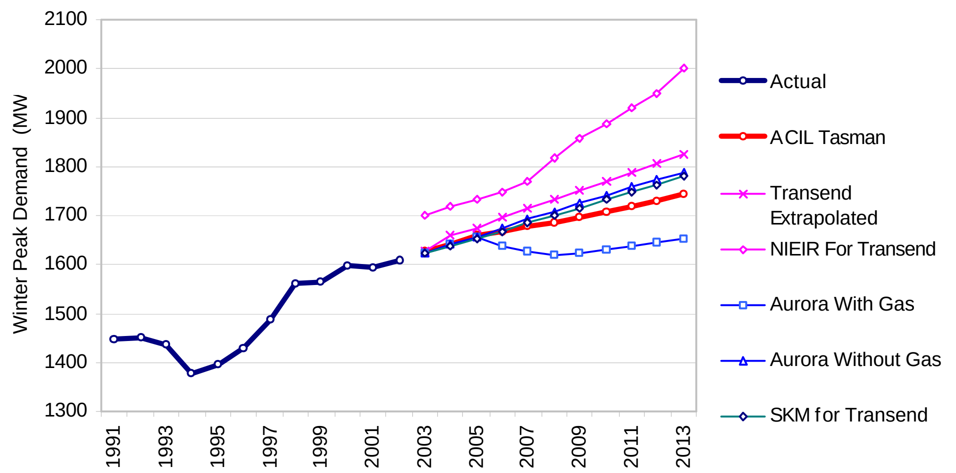
ACIL Tasman has examined load factor (quoted as the percentage average demand for the year is of peak winter demand) for the Tasmanian system and found it varied from a low of 70.7% in 1994/95 to a high of 74.0% in 1997/98. The load factor in the last two years has been steady at 72.4%. The trend in the load factor is difficult to discern however apart from three high years probably with mild winters there is a definite upward trend in load factor. This suggests that future growth in peak demand is likely to be less than the growth in annual energy. This trend will be reinforced by the introduction of natural gas which, through its impact on electrical space and water heating, can be expected to reduce winter peak demand by a greater percentage than annual energy. For these reasons ACIT Tasman has forecast a gradual increase in load factor meaning a slightly lower growth in winter peak demand than in annual energy. The NIEIR for Transend seems inconsistent with recorded history. The forecast load factors from the various forecasts are presented in Figure 24.

Figure 24 **Comparison of Load Factor Forecasts for Tasmania**



The resultant winter demand forecast by ACIL Tasman is shown in Figure 25. Again the winter peak demand forecast by ACIL Tasman is lower than Transend extrapolated, SKM and Aurora without gas but higher than Aurora with gas. The ACIL Tasman forecast growth in winter peak demand averages 0.74% per annum which compares with 0.26% for Aurora with gas, 0.94% for Aurora without gas, 0.99% for SKM and 1.16% for Transend extrapolated.

Figure 25 **Forecast of Generated Winter Peak Demand (without Basslink) (MW)**



1.2.6 Operation of Basslink

Modelling of the NEM by ACIL Tasman using its PowerMark model of the NEM, shows that flows on Basslink will be northerly from Tasmania to Victoria during week day peak periods but in the opposite direction in the off-peak and weekends. This means that at the time of the winter peak in Tasmania the flow on Basslink will be in a northerly direction at close to the link's long term rating of 500MW which adds to the peak loading on both the Tasmanian transmission system and generators.

The modelling also shows that in most years more energy flows from Victoria to Tasmania that from Tasmania to Victoria thereby reducing stress on the water storages in Tasmania. This should also mean that the Tasmanian hydro plant will be ideally placed to provide energy into Victoria during the higher priced peak periods. The modeled flows on Basslink are shown in Table 2

Table 2 **Flows on Basslink from ACIL Tasman Modelling of the NEM**

Year ending in June	Annual Energy Flow s			% of Time Flow ing		% of Time Saturated	
	Vic to Tas	Tas to Vic	Net Flow to Tasmania	Vic to Tas	Tas to Vic	Vic to Tas	Tas to Vic
2005	561	874	-313	49%	51%	37%	34%
2006	1,673	1,031	642	69%	31%	58%	19%
2007	1,613	1,193	420	66%	34%	56%	23%
2008	1,565	1,320	244	64%	36%	55%	26%
2009	1,520	1,399	121	62%	38%	53%	27%
2010	1,489	1,427	62	61%	39%	52%	27%
2011	1,471	1,440	31	60%	40%	51%	27%
2012	1,590	1,248	342	65%	35%	56%	21%

Table 3 shows the peak demand and energy forecasts for the Tasmanian transmission system and generators including the effect of Basslink.

Table 3 **Forecast for Peak Demand and Energy Including Basslink**

Year Ending June	Annual Generated Energy (GWh)			Generated Winter Peak Demand (MW)		
	Tasmanian Loads	Net flow on Basslink	Total for Tasmania	Tasmanian Loads	Net flow on Basslink	Total for Tasmania
2003	10316	0	10316	1627	0	1627
2004	10419	0	10419	1643	0	1643
2005	10523	313	10837	1658	480	2138
2006	10588	-642	9946	1667	480	2147
2007	10656	-420	10236	1677	454	2130
2008	10725	-244	10481	1686	461	2147
2009	10800	-121	10678	1697	457	2154
2010	10876	-62	10814	1708	451	2159
2011	10955	-31	10924	1719	453	2172
2012	11036	-342	10694	1731	425	2155
2013	11120	-350	10770	1742	480	2222

1.2.7 Regional and Substation Forecasts

ACIL Tasman adopted the following approach to developing the substation forecast:

Step 1. Apply a 4.4% distribution loss factor to the sales forecast for tariff customers and 0.0% to the sales forecast for major industrial customers (see Table 1) to give an energy forecast at the terminal substations.

Step 2. Prepare a forecast of annual energy including distribution losses for the 12 regions (as defined in the Aurora forecast) to be consistent with the overall ACIL Tasman forecast in Step 1 and taking into account regional growth in recent years and the possible impact of the introduction of natural gas. Tariff and major industrial customers are considered separately.

Step 3. Prepare a forecast of annual energy at each substation ensuring that the total energy matched the regional energy forecast.

Step 4. Determine appropriate winter and summer load factors for each substation based on outcomes over the past four years.

Step 5. Apply the substation winter and summer load factors to the annual energy forecast by substation (Step 3) to produce a winter peak forecast (MW) and a summer peak forecast by substation.

Step 6. Examine the past substation MW coincidence factors and select an appropriate factor to apply to the winter peak to give the contribution of the individual substations to the winter peak and ensure consistency with the overall winter peak forecast.

Step 7. Determine appropriate winter and summer power factors for each substation based on outcomes over the past four years.

Step 8. Apply the power factors to the winter and summer peak MW forecast to produce forecasts of peak winter MVA and peak summer MVA and Coincident peak MVA.

Regional Energy Forecast

Using the same twelve regions as in the Aurora Substation Forecast, ACIL Tasman produces a revised regional energy forecast as shown in Table 4 to Table 6. In both the ACIL Tasman and Aurora (without gas) forecasts the East Coast, Midlands North and South East regions have the highest forecast growth but the ACIL Tasman Growth rates are noticeably lower than those of Aurora forecast mainly because the ACIL Tasman forecast growth is lower overall and incorporates an allowance for the impact of gas on heating loads. The higher growth in the North West region forecast by ACIL Tasman is because it includes allowance for some growth in major industrial loads whereas Aurora forecast does not.

Table 4 **Forecast of Tariff Customer Energy by Twelve Regions (GWh at substations)**

Region	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Historic Grow th 1998/99 to 2001/02	AT Forecast Grow th 2002/03 to 2012/13	Aurora Forecast Grow th (Without Gas)
Central North	766	781	789	796	797	797	798	800	802	804	806	809	1.1%	0.5%	-0.3%
Derw ent Clyde	181	186	190	194	196	198	200	203	205	208	210	213	2.3%	1.5%	2.7%
East Coast	61	64	66	68	69	70	72	73	75	77	79	80	7.7%	2.5%	5.6%
Highlands	13	13	14	14	14	14	14	14	15	15	15	15	14.9%	1.5%	1.3%
Hobart Urban	1200	1223	1235	1247	1247	1248	1250	1252	1255	1259	1263	1267	0.9%	0.5%	0.7%
Midlands North	56	58	59	60	61	61	62	63	63	64	65	66	2.4%	1.5%	1.9%
North East	98	100	101	101	101	101	101	101	101	101	101	101	0.3%	0.3%	1.5%
North West	108	111	112	114	114	115	116	116	117	118	119	120	1.8%	0.9%	0.9%
South East	97	100	102	104	105	106	107	108	110	111	112	114	2.8%	1.5%	3.5%
Southern	238	246	252	258	262	266	271	275	280	285	290	295	3.1%	2.0%	3.5%
Tamar	893	915	930	945	951	957	964	972	980	988	998	1007	1.9%	1.1%	1.6%
West Coast	47	48	48	49	49	49	49	49	50	50	50	50	1.5%	0.7%	1.6%
Total Tariff	3757	3843	3896	3950	3966	3984	4003	4027	4052	4079	4108	4139	1.6%	0.89%	1.27%

Table 5 **Forecast of Major Industrial Energy by Twelve Regions (GWh at substations)**

Region	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Historic Grow th 1998/99 to 2001/02	AT Forecast Grow th 2002/03 to 2012/13	Aurora Forecast Grow th (Without Gas)
Central North	373	375	378	381	384	386	389	392	395	398	401	404	-6.1%	0.7%	0.5%
Derw ent Clyde	632	633	635	637	638	640	642	643	645	647	648	650	0.8%	0.3%	0.8%
East Coast	5	5	5	5	5	5	5	5	5	5	5	5	-13.0%	0.0%	0.0%
Highlands	44	44	44	44	44	44	44	44	44	44	44	44	-1.8%	0.0%	0.0%
Hobart Urban	1038	1046	1054	1062	1070	1078	1086	1094	1102	1110	1117	1125	2.7%	0.7%	0.7%
Midlands North															
North East															
North West	91	92	93	94	94	95	96	97	98	98	99	100	62.2%	0.8%	0.0%
South East															
Southern															
Tamar	3297	3323	3350	3378	3405	3433	3461	3490	3518	3547	3576	3605	2.2%	0.8%	0.7%
West Coast	470	473	477	481	484	488	491	495	499	502	506	510	4.6%	0.8%	0.0%
	5950	5993	6036	6080	6125	6169	6214	6260	6305	6351	6397	6444	2.0%	0.73%	0.65%

Table 6 **Forecast of Total Energy by Twelve Regions (GWh at substations)**

Region	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Historic Grow th 1998/99 to 2001/02	AT Forecast Grow th 2001/02 to 2012/13	Aurora Forecast Grow th (Without Gas)
Central North	1139	1156	1167	1177	1180	1184	1187	1192	1197	1202	1207	1213	-1.6%	0.6%	0.0%
Derw ent Clyde	813	820	825	831	834	838	842	846	850	854	859	863	1.1%	0.5%	1.2%
East Coast	66	69	71	73	74	75	77	79	80	82	84	86	5.1%	2.3%	5.3%
Highlands	57	57	58	58	58	58	58	59	59	59	59	59	0.9%	0.4%	0.3%
Hobart Urban	2237	2268	2289	2309	2317	2326	2335	2346	2357	2368	2380	2393	1.7%	0.6%	0.7%
Midlands North	56	58	59	60	61	61	62	63	63	64	65	66	2.4%	1.5%	1.9%
North East	98	100	101	101	101	101	101	101	101	101	101	101	0.3%	0.3%	1.5%
North West	200	203	205	208	209	210	211	213	215	216	218	220	15.0%	0.9%	0.5%
South East	97	100	102	104	105	106	107	108	110	111	112	114	2.8%	1.5%	3.5%
Southern	238	246	252	258	262	266	271	275	280	285	290	295	3.1%	2.0%	3.5%
Tamar	4190	4239	4280	4323	4356	4390	4425	4461	4498	4535	4573	4612	2.2%	0.9%	0.9%
West Coast	516	521	525	529	533	537	541	544	548	552	556	560	4.3%	0.7%	0.2%
Total Tasmania	9707	9836	9933	10030	10091	10153	10218	10286	10357	10430	10506	10583	1.8%	0.79%	0.89%

Substation Energy Forecast

The forecast of annual energy at each substation which is consistent with the regional energy forecast and past trends in substation energy is shown in Table 7.

Table 7 **Forecast of Energy at Substations (GWh at substations)**

Terminal substation	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Arthurs Lake	44	45	45	45	45	45	45	45	46	46	46	46
Avoca	25	26	26	27	27	27	28	28	28	29	29	29
Boyer	632	633	635	637	638	640	642	643	645	647	648	650
Bridgewater	84	88	91	95	97	100	103	105	108	111	114	118
Burnie	230	233	234	235	235	235	234	234	234	234	234	234
Chapel Street	178	182	185	188	190	191	192	194	196	198	199	201
CMT	113	114	115	117	119	120	122	123	125	127	128	130
Comalco 220kV	2477	2497	2516	2536	2556	2576	2596	2617	2637	2658	2679	2700
Creek Road	276	279	279	279	276	273	271	269	266	264	262	260
Derby	15	16	16	17	17	17	17	18	18	18	19	19
Derwent Bridge	1	1	1	1	1	1	1	1	1	1	1	1
Devonport	222	223	223	223	221	219	217	215	214	212	211	209
Electrona	36	37	38	39	40	41	42	43	44	45	46	47
Emu Bay AP	92	92	92	93	93	93	93	94	94	94	94	95
Emu Bay Retail	34	34	34	35	34	34	34	34	34	34	34	34
Fisher	0	0	0	0	0	0	0	0	0	0	0	0
Georgetown	114	116	116	117	116	116	116	115	115	115	114	114
Gordon	3	3	3	3	3	3	3	3	3	3	3	3
Hampshire	6	6	6	6	6	6	6	6	6	6	6	6
Henty Goldmine (Renison)	11	11	11	12	12	12	12	12	12	12	12	12
Hokushin (Starwood)	44	45	46	47	47	47	48	48	48	49	49	50
Kermandie	26	27	28	28	29	29	29	30	30	31	31	32
Kingston	117	121	124	127	129	131	133	136	138	140	143	146
Knights Road	59	61	62	63	64	65	66	67	68	69	70	71
Lindisfarne	191	195	198	200	201	202	202	203	204	205	206	207
Meadowbank	23	23	23	23	23	23	23	23	23	23	23	23
New Norfolk	74	75	76	76	75	75	75	74	74	74	73	73
Newton Pumps	14	14	14	14	14	14	14	14	14	14	14	14
North Hobart	226	230	231	232	231	230	229	228	227	226	226	225
Norwood	242	247	250	253	254	255	257	258	259	261	262	264
Palmerston	31	32	33	33	34	34	34	35	35	36	36	37
Port Latta	91	93	94	94	95	95	96	96	97	97	98	99
Que	4	4	4	4	4	4	4	4	4	4	4	4
Queenstown	28	29	29	30	31	32	32	33	34	35	35	36
Railton	269	277	282	288	292	296	300	304	309	313	318	323
Risdon 11kV	1011	1019	1027	1035	1043	1052	1060	1069	1077	1086	1094	1103
Risdon 22kV	267	275	280	286	288	291	294	298	301	305	309	313
Rokeby	88	89	89	89	88	87	87	86	85	84	84	83
Rosebery 22kV	19	19	19	19	20	20	20	20	20	20	20	21
Rosebery 44kV	171	172	173	174	175	175	176	176	177	177	178	179
Savage River	157	157	158	159	160	160	161	162	163	163	164	165
Scottsdale	83	84	84	85	84	84	84	83	83	83	83	82
Smithton	108	110	112	113	114	115	116	117	118	119	120	121
Sorell	97	100	102	104	105	106	107	108	110	111	112	114
St Marys	45	47	48	50	51	52	53	54	55	56	58	59
Temco	765	771	778	785	791	798	805	812	819	826	833	840
Trevallyn	547	562	573	585	591	598	604	612	619	627	636	644
Triabunna	21	22	22	23	23	24	24	25	25	26	26	27
Tungatinah	3	3	3	3	3	3	3	3	3	3	3	3
Ulverstone	148	152	155	158	160	162	164	166	169	171	173	176
Waddamana	1	1	1	1	1	1	1	1	1	1	1	1
Wayatinah	5	5	5	5	5	5	5	5	5	5	5	5
Wesley Vale	137	138	139	139	139	138	138	138	138	137	137	137

Substation Winter Peak Demand Forecast (MW)

Applying the estimated substation winter load factors to annual energy produces the substation winter peak demand forecast in MW as shown in Table 8.

Table 8 **Forecast of Winter Peak Demand at Substations (MW)**

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Arthurs Lake	7	7	7	7	7	7	7	7	7	7	7	7
Avoca	5	6	7	7	7	7	7	7	7	7	7	7
Boyer	81	81	81	81	81	82	82	82	82	83	83	83
Bridgew ater	24	25	26	27	28	29	30	30	31	32	33	34
Burnie	54	53	53	54	54	54	54	53	53	53	53	53
Chapel Street	48	47	48	49	49	50	50	50	51	51	52	52
CMT	15	15	15	16	16	16	16	16	17	17	17	17
Comalco 220kV	286	288	290	292	295	297	299	302	304	307	309	311
Creek Road	78	71	71	71	70	69	69	68	68	67	66	66
Derby	3	3	3	3	3	3	3	3	3	3	3	4
Derw ent Bridge	0	0	0	0	0	0	0	0	0	0	0	0
Devonport	52	53	52	52	52	51	51	51	50	50	50	49
Electrona	11	11	12	12	12	12	13	13	13	14	14	14
Emu Bay AP	14	14	14	14	14	14	14	14	14	14	14	14
Emu Bay Retail	9	9	9	9	9	9	9	9	9	9	9	9
Fisher	0	0	0	0	0	0	0	0	0	0	0	0
Georgetow n	25	24	24	24	24	24	24	24	24	24	24	24
Gordon	1	1	1	1	1	1	1	1	1	1	1	1
Hampshire	2	2	2	2	2	2	2	2	2	2	2	2
Henty Goldmine (	3	2	2	2	2	2	2	2	2	2	2	2
Hokushin (Starw	9	9	9	9	9	9	9	9	9	9	9	9
Kermandie	5	6	6	6	6	6	6	6	6	6	7	7
Kingston	33	34	35	36	36	37	37	38	39	39	40	41
Knights Road	13	13	14	14	14	14	14	15	15	15	15	16
Lindisfarne	51	52	53	53	53	54	54	54	54	54	55	55
Meadow bank	5	5	5	5	5	5	5	4	4	4	4	4
New Norfolk	15	15	15	15	15	15	15	15	15	15	14	14
New ton Pumps	5	5	5	5	5	5	5	5	5	5	5	5
North Hobart	63	64	65	65	65	64	64	64	64	63	63	63
Norw ood	63	64	65	66	66	66	67	67	67	68	68	69
Palmerston	6	6	6	6	6	6	7	7	7	7	7	7
Port Latta	13	13	13	13	13	13	13	14	14	14	14	14
Que	1	1	1	1	1	1	1	1	1	1	1	1
Queenstow n	7	7	7	7	8	8	8	8	8	8	9	9
Railton	45	48	49	50	51	52	52	53	54	55	56	56
Risdon 11kV	121	122	123	124	125	126	127	128	129	130	131	132
Risdon 22kV	69	70	71	72	73	74	75	76	76	77	78	79
Rokeby	26	26	26	26	26	26	26	25	25	25	25	25
Rosebery 22kV	4	5	5	5	5	5	5	5	5	5	5	5
Rosebery 44kV	20	20	20	20	20	20	20	20	20	20	20	20
Savage River	19	22	22	22	22	22	22	23	23	23	23	23
Scottsdale	16	16	16	16	16	16	16	16	16	16	16	16
Smithton	21	20	21	21	21	21	21	21	22	22	22	22
Sorell	23	23	23	24	24	24	24	25	25	25	26	26
St Marys	12	12	13	13	13	13	14	14	14	15	15	15
Temco	101	106	107	108	109	110	111	112	113	114	115	116
Trevallyn	133	137	139	142	144	145	147	149	150	152	154	156
Triabunna	7	6	6	6	6	6	7	7	7	7	7	7
Tungatinah	1	1	1	1	1	1	1	1	1	1	1	1
Ulverstone	32	32	32	33	33	34	34	35	35	35	36	36
Waddamana	0	0	0	0	0	0	0	0	0	0	0	0
Wayatinah	1	1	1	1	1	1	1	1	1	1	1	1
Wesley Vale	23	23	23	23	23	23	23	23	23	23	23	23

Substation Summer Peak Demand Forecast (MW)

Applying the estimated substation summer load factors to annual energy produces the substation summer peak demand forecast in MW as shown in Table 9

Table 9 **Forecast of Summer Peak Demand at Substations (MW)**

Terminal substation	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Arthurs Lake	7	7	7	7	7	7	7	7	7	7	7	7
Avoca	6	6	7	7	7	7	7	7	7	7	7	7
Boyer	80	81	81	82	82	82	82	83	83	83	83	83
Bridgewater	21	17	17	18	19	19	20	20	21	21	22	22
Burnie	41	38	38	38	38	38	38	38	38	38	38	38
Chapel Street	37	32	33	33	33	34	34	34	34	35	35	35
CMT	15	15	15	16	16	16	16	16	17	17	17	17
Comalco 220kV	286	288	290	292	294	296	298	301	303	305	307	310
Creek Road	56	45	45	45	45	45	44	44	43	43	43	42
Derby	6	6	6	7	7	7	7	7	7	7	7	8
Derwent Bridge	0	0	0	0	0	0	0	0	0	0	0	0
Devonport	37	37	37	37	37	37	36	36	36	35	35	35
Electrona	8	6	6	7	7	7	7	7	7	7	8	8
Emu Bay AP	14	14	14	14	14	14	14	14	14	14	14	14
Emu Bay Retail	7	7	7	7	7	7	7	7	7	7	7	7
Fisher	0	0	0	0	0	0	0	0	0	0	0	0
Georgetown	20	20	20	21	20	20	20	20	20	20	20	20
Gordon	1	1	1	1	1	1	1	1	1	1	1	1
Hampshire	2	1	1	1	1	1	1	1	1	1	1	1
Henty Goldmine (Renison	3	2	2	2	2	2	2	2	2	2	2	2
Hokushin (Starwood)	9	9	9	9	9	9	9	9	10	10	10	10
Kermandie	5	4	5	5	5	5	5	5	5	5	5	5
Kingston	32	26	27	27	28	28	29	29	30	30	31	31
Knights Road	11	10	11	11	11	11	11	11	12	12	12	12
Lindisfarne	37	34	35	35	35	35	36	36	36	36	36	36
Meadowbank	5	5	5	5	5	5	5	5	5	5	5	5
New Norfolk	14	14	14	14	14	14	14	13	13	13	13	13
Newton Pumps	3	3	3	3	3	3	3	3	3	3	3	3
North Hobart	47	42	42	42	42	42	41	41	41	41	41	41
Norwood	47	43	44	45	45	45	45	45	46	46	46	46
Palmerston	7	10	11	11	11	11	11	11	11	12	12	12
Port Latta	15	16	16	16	16	16	16	16	16	16	16	17
Que	1	1	1	1	1	1	1	1	1	1	1	1
Queenstown	5	5	5	5	6	6	6	6	6	6	6	7
Railton	45	49	50	51	51	52	53	53	54	55	56	57
Risdon 11kV	123	124	125	126	127	128	129	130	131	132	133	134
Risdon 22kV	52	48	49	50	51	51	52	52	53	54	54	55
Rokeby	19	17	17	17	17	17	16	16	16	16	16	16
Rosebery 22kV	4	3	3	4	4	4	4	4	4	4	4	4
Rosebery 44kV	20	20	20	20	20	20	20	20	20	20	20	20
Savage River	20	21	21	21	21	21	21	21	21	21	22	22
Scottsdale	15	15	15	15	15	15	15	15	15	15	15	15
Smithton	20	21	22	22	22	22	22	23	23	23	23	23
Sorell	19	18	19	19	19	19	20	20	20	20	21	21
St Marys	10	10	10	10	11	11	11	11	11	12	12	12
Temco	103	106	107	108	109	110	111	112	113	114	115	116
Trevallyn	99	92	94	95	96	97	99	100	101	102	104	105
Triabunna	6	6	6	6	6	6	6	7	7	7	7	7
Tungatinah	1	1	1	1	1	1	1	1	1	1	1	1
Ulverstone	25	26	26	27	27	28	28	28	29	29	30	30
Waddamana	0	0	0	0	0	0	0	0	0	0	0	0
Wayatinah	2	2	2	2	2	2	2	2	2	2	2	2
Wesley Vale	24	24	24	24	24	24	24	24	24	24	24	24

Substation Coincident Demand at Winter Peak (MW)

Applying the estimated substation coincidence factors to substation winter peak forecast produces the substation contribution the Tasmanian winter peak demand MW as shown in Table 10

Table 10 **Forecast of Substation Coincident Demand at Winter Peak (MW)**

Terminal Substation	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Arthurs Lake	7	7	7	7	7	7	7	7	7	7	7	7
Avoca	5	6	6	6	6	6	6	6	6	6	6	7
Boyer	77	76	76	76	76	76	76	77	77	77	77	77
Bridgew ater	20	22	22	23	24	24	25	26	26	27	28	29
Burnie	53	48	49	49	49	49	49	49	49	48	48	48
Chapel Street	47	46	47	48	48	49	49	49	50	50	51	51
CMT	14	15	15	15	15	16	16	16	16	16	17	17
Comalco 220kV	283	283	285	287	289	292	294	296	298	300	303	305
Creek Road	75	70	70	69	69	68	67	67	66	66	65	65
Derby	2	2	2	2	2	2	2	2	2	2	2	2
Derw ent Bridge	0	0	0	0	0	0	0	0	0	0	0	0
Devonport	44	44	44	44	43	43	43	42	42	42	41	41
Electrona	10	8	9	9	9	9	9	10	10	10	10	11
Emu Bay AP	10	11	11	11	11	11	11	11	11	11	11	11
Emu Bay Retail	6	7	7	7	7	7	7	7	7	7	7	7
Fisher	0	0	0	0	0	0	0	0	0	0	0	0
Georgetow n	18	19	19	19	19	19	18	18	18	18	18	18
Gordon	0	0	0	0	0	0	0	0	0	0	0	0
Hampshire	2	2	2	2	2	2	2	2	2	2	2	2
Henty Goldmine (Renison)	3	2	2	2	2	2	2	2	2	2	2	2
Hokushin (Starw ood)	1	3	3	3	4	4	4	4	4	4	4	4
Kermandie	5	5	5	6	6	6	6	6	6	6	6	6
Kingston	29	31	32	32	33	33	34	34	35	36	36	37
Knights Road	13	13	13	14	14	14	14	14	15	15	15	15
Lindisfarne	49	48	48	49	49	49	49	49	50	50	50	50
Meadow bank	4	4	4	4	4	4	4	4	4	4	4	4
New Norfolk	13	13	13	14	13	13	13	13	13	13	13	13
New ton Pumps	0	5	5	5	5	5	5	5	5	5	5	5
North Hobart	47	53	53	53	53	52	52	52	52	52	52	51
Norw ood	55	62	62	63	63	64	64	64	64	65	65	66
Palmerston	5	5	6	6	6	6	6	6	6	6	6	6
Port Latta	11	11	11	11	11	11	11	11	11	11	12	12
Que	0	0	0	0	0	0	0	0	0	0	0	0
Queenstow n	6	6	6	6	7	7	7	7	7	7	8	8
Railton	29	39	40	40	41	41	42	43	43	44	44	45
Risdon 11kV	115	114	115	116	117	118	119	120	121	121	122	123
Risdon 22kV	62	62	63	64	65	65	66	67	67	68	69	70
Rokeby	25	23	23	23	22	22	22	22	22	21	21	21
Rosebery 22kV	4	4	4	4	4	4	4	4	4	4	4	4
Rosebery 44kV	18	19	19	19	20	20	20	20	20	20	20	20
Savage River	18	19	19	19	19	20	20	20	20	20	20	20
Scottsdale	14	14	14	14	14	14	14	14	14	14	14	14
Smithton	17	18	18	18	18	18	19	19	19	19	19	19
Sorell	22	22	22	23	23	23	23	24	24	24	25	25
St Marys	8	9	10	10	10	10	10	11	11	11	11	12
Temco	87	90	91	92	92	93	94	95	95	96	97	98
Trevallyn	119	129	131	134	135	137	138	140	141	143	145	147
Triabunna	4	4	4	4	4	5	5	5	5	5	5	5
Tungatinah	1	1	1	1	1	1	1	1	1	1	1	1
Ulverstone	32	31	31	32	32	32	33	33	34	34	35	35
Waddamana	0	0	0	0	0	0	0	0	0	0	0	0
Wayatinah	1	1	1	1	1	1	1	1	1	1	1	1
Wesley Vale	16	18	18	18	18	18	18	18	18	18	18	18

Substation Winter Peak Demand Forecast (MVA)

Applying the estimated substation winter power factors to winter peak demand in MW produces the substation winter peak demand forecast in MVA as shown in Table 11.

Table 11 **Forecast of Winter Peak Demand at Substations (MVA)**

Terminal substation	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Arthurs Lake	7	7	7	7	7	7	7	7	7	7	7	7
Avoca	5	6	7	7	7	7	7	7	7	7	7	7
Boyer	89	89	89	90	90	90	90	91	91	91	91	91
Bridgew ater	25	26	27	28	28	29	30	31	32	33	33	34
Burnie	56	55	55	56	55	55	55	55	55	55	55	55
Chapel Street	49	48	49	50	50	51	51	52	52	52	53	53
CMT	20	20	20	20	21	21	21	21	22	22	22	23
Comalco 220kV	297	299	301	303	306	308	311	313	315	318	320	323
Creek Road	78	71	71	71	70	69	69	68	68	67	66	66
Derby	0	3	3	3	3	3	3	3	3	3	4	4
Derw ent Bridge	0	0	0	0	0	0	0	0	0	0	0	0
Devonport	55	55	55	55	54	54	53	53	52	52	52	51
Electrona	11	12	12	12	13	13	13	13	14	14	14	15
Emu Bay AP	15	16	16	16	16	16	16	16	16	16	16	16
Emu Bay Retail	9	9	9	9	9	9	9	9	9	9	9	9
Fisher	0	0	0	0	0	0	0	0	0	0	0	0
Georgetow n	27	26	26	26	26	26	26	26	26	26	26	26
Gordon	1	1	1	1	1	1	1	1	1	1	1	1
Hampshire	2	2	2	2	2	2	2	2	2	2	2	2
Henty Goldmine (Renison)	4	2	2	2	2	2	2	2	2	2	2	2
Hokushin (Starw ood)	10	9	10	10	10	10	10	10	10	10	10	10
Kermandie	6	6	6	6	6	6	7	7	7	7	7	7
Kingston	33	34	35	36	37	37	38	38	39	40	41	41
Knights Road	14	14	15	15	15	15	15	16	16	16	16	17
Lindisfarne	54	54	55	55	56	56	56	56	56	57	57	57
Meadow bank	5	5	5	5	5	5	5	5	5	5	5	5
New Norfolk	15	15	15	15	15	15	15	15	15	15	15	15
Newton Pumps	0	6	6	6	6	6	6	6	6	6	6	6
North Hobart	68	69	69	69	69	69	69	68	68	68	68	68
Norw ood	65	66	67	68	68	69	69	69	70	70	70	71
Palmerston	6	6	7	7	7	7	7	7	7	7	7	7
Port Latta	15	15	15	15	15	16	16	16	16	16	16	16
Que	1	1	1	1	1	1	1	1	1	1	1	1
Queenstow n	6	7	7	7	8	8	8	8	8	9	9	9
Railton	53	52	53	54	55	55	56	57	58	59	59	60
Risdon 11kV	129	130	131	132	133	134	135	136	137	138	139	141
Risdon 22kV	74	74	76	77	78	79	80	81	81	82	83	85
Rokeby	27	28	28	28	27	27	27	26	26	26	26	26
Rosebery 22kV	5	5	5	5	5	5	5	5	5	5	5	5
Rosebery 44kV	18	20	20	20	20	20	20	20	20	20	20	20
Savage River	21	23	24	24	24	24	24	24	24	24	24	25
Scottsdale	0	17	17	17	17	17	17	17	17	17	17	17
Smithton	22	22	22	22	22	23	23	23	23	23	24	24
Sorell	23	23	24	24	24	24	25	25	25	26	26	26
St Marys	12	13	13	13	14	14	14	15	15	15	16	16
Temco	102	107	108	109	110	111	112	113	114	115	116	117
Trevallyn	133	137	139	142	144	145	147	149	151	153	155	157
Triabunna	7	6	6	6	6	7	7	7	7	7	7	7
Tungatinah	1	1	1	1	1	1	1	1	1	1	1	1
Ulverstone	33	33	33	34	34	35	35	36	36	37	37	38
Waddamana	0	0	0	0	0	0	0	0	0	0	0	0
Wayatinah	1	1	1	1	1	1	1	1	1	1	1	1
Wesley Vale	26	26	26	26	26	26	26	26	26	26	26	26

Substation Summer Peak Demand Forecast (MVA)

Applying the estimated substation summer power factors to peak summer peak demand in MW produces the substation summer peak demand forecast in MVA as shown in Table 12.

Table 12 **Forecast of Summer Peak Demand at Substations (MVA)**

Terminal substation	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Arthurs Lake	7	7	7	7	7	7	8	8	8	8	8	8
Avoca	7	7	7	7	7	7	7	8	8	8	8	8
Boyer	89	90	90	90	90	91	91	91	91	92	92	92
Bridgewater	21	17	18	18	19	19	20	20	21	21	22	23
Burnie	43	41	41	41	41	41	41	41	41	41	41	41
Chapel Street	38	33	33	34	34	34	35	35	35	35	36	36
CMT	18	19	19	19	19	20	20	20	20	21	21	21
Comalco 220kV	296	298	300	303	305	307	309	312	314	316	318	321
Creek Road	66	54	54	54	54	53	53	52	52	51	51	51
Derby	0	7	7	7	7	7	7	7	8	8	8	8
Derwent Bridge	0	0	0	0	0	0	0	0	0	0	0	0
Devonport	40	40	40	40	39	39	39	38	38	38	38	37
Electrona	9	6	7	7	7	7	7	7	8	8	8	8
Emu Bay AP	15	15	15	15	15	15	15	15	15	15	15	15
Emu Bay Retail	7	7	7	7	7	7	7	7	7	7	7	7
Fisher	0	0	0	0	0	0	0	0	0	0	0	0
Georgetown	20	21	21	21	21	21	21	21	21	21	21	21
Gordon	1	1	1	1	1	1	1	1	1	1	1	1
Hampshire	2	1	1	1	1	1	1	1	1	1	1	1
Henty Goldmine (Reniso	3	2	2	2	2	2	2	2	2	2	2	2
Hokushin (Starwood)	10	10	10	10	10	10	10	11	11	11	11	11
Kermandie	5	5	5	5	5	5	5	5	5	5	5	5
Kingston	33	27	27	28	28	29	29	30	30	31	31	32
Knights Road	12	11	12	12	12	12	12	12	13	13	13	13
Lindisfarne	39	36	37	37	37	37	37	38	38	38	38	38
Meadowbank	5	5	5	5	5	5	5	5	5	5	5	5
New Norfolk	14	14	14	14	14	14	14	14	14	14	13	13
Newton Pumps	0	3	3	3	3	3	3	3	3	3	3	3
North Hobart	50	45	45	45	45	45	45	44	44	44	44	44
Norwood	50	46	47	48	48	48	48	48	49	49	49	50
Palmerston	7	11	11	12	12	12	12	12	12	12	12	13
Port Latta	17	18	18	18	19	19	19	19	19	19	19	19
Que	1	1	1	1	1	1	1	1	1	1	1	1
Queenstown	6	5	5	6	6	6	6	6	6	6	7	7
Railton	55	54	55	56	56	57	58	59	60	61	61	62
Risdon 11kV	128	129	130	131	132	133	134	135	136	137	138	139
Risdon 22kV	59	55	56	57	58	58	59	60	60	61	62	63
Rokeby	20	17	17	17	17	17	17	17	16	16	16	16
Rosebery 22kV	4	4	4	4	4	4	4	4	4	4	4	4
Rosebery 44kV	17	20	20	20	20	20	20	20	20	20	20	20
Savage River	21	22	23	23	23	23	23	23	23	23	23	24
Scottsdale	0	17	17	17	17	17	17	17	17	17	17	17
Smithton	23	25	25	25	25	26	26	26	26	27	27	27
Sorell	20	19	19	19	20	20	20	20	21	21	21	21
St Marys	11	10	10	11	11	11	11	12	12	12	12	13
Temco	104	107	108	109	110	111	112	113	114	115	116	117
Trevallyn	104	97	99	101	102	103	104	105	107	108	109	111
Triabunna	6	6	6	6	6	6	7	7	7	7	7	7
Tungatinah	1	1	1	1	1	1	1	1	1	1	1	1
Ulverstone	28	28	29	29	30	30	31	31	31	32	32	33
Waddamana	0	0	0	0	0	0	0	0	0	0	0	0
Wayatinah	2	2	2	2	2	2	2	2	2	2	2	2
Wesley Vale	28	28	28	28	28	28	28	28	28	28	28	28

Substation Coincident Demand at Winter Peak (MVA)

Applying the estimated substation coincidence factors to substation winter peak forecast in MVA produces the substation contribution the Tasmanian winter MVA peak demand as shown in Table 13

Table 13 **Substation Coincident Demand at Winter Peak (MVA)**

Year Ending 30 June	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Arthurs Lake	7	7	7	7	7	7	7	7	7	7	7	7
Avoca	5	6	6	6	6	6	6	6	6	6	6	7
Boyer	85	83	84	84	84	84	84	84	85	85	85	85
Bridgewater	21	22	23	23	24	25	25	26	27	28	28	29
Burnie	55	50	50	51	50	50	50	50	50	50	50	50
Chapel Street	48	48	48	49	49	50	50	51	51	51	52	52
CMT	18	19	20	20	20	20	21	21	21	22	22	22
Comalco 220kV	293	294	296	298	300	302	305	307	309	312	314	316
Creek Road	75	70	70	69	69	68	67	67	66	66	65	65
Derby	0	2	2	2	2	2	2	2	2	2	2	3
Derwent Bridge	0	0	0	0	0	0	0	0	0	0	0	0
Devonport	46	46	46	46	45	45	45	44	44	43	43	43
Electrona	11	9	9	9	9	9	10	10	10	10	11	11
Emu Bay AP	11	12	12	12	12	12	12	12	12	12	12	12
Emu Bay Retail	6	7	7	7	7	7	7	7	7	7	7	7
Fisher	0	0	0	0	0	0	0	0	0	0	0	0
Georgetown	20	20	20	20	20	20	20	20	20	20	20	20
Gordon	0	0	0	0	0	0	0	0	0	1	0	0
Hampshire	2	2	2	2	2	2	2	2	2	2	2	2
Henty Goldmine (Renison)	3	2	2	2	2	2	2	2	2	2	2	2
Hokushin (Starwood)	1	4	4	4	4	4	4	4	4	4	4	4
Kermandie	6	6	6	6	6	6	6	6	6	6	6	7
Kingston	29	31	32	33	33	34	34	35	36	36	37	37
Knights Road	14	14	14	15	15	15	15	15	16	16	16	16
Lindisfarne	51	50	50	51	51	51	51	52	52	52	52	52
Meadowbank	4	4	4	4	4	4	4	4	4	4	4	4
New Norfolk	14	14	14	14	14	14	13	13	13	13	13	13
Newton Pumps	0	5	5	5	5	5	5	5	5	5	5	5
North Hobart	51	56	57	57	57	56	56	56	56	55	55	55
Norwood	57	64	65	65	66	66	66	66	67	67	67	68
Palmerston	5	6	6	6	6	6	6	6	6	6	6	7
Port Latta	13	13	13	13	13	13	13	13	13	13	13	13
Que	0	0	0	0	0	0	0	0	0	0	0	0
Queenstown	5	6	6	7	7	7	7	7	7	8	8	8
Railton	35	42	42	43	44	44	45	46	46	47	47	48
Risdon 11kV	123	122	123	124	125	125	126	127	128	129	130	131
Risdon 22kV	66	66	67	68	69	70	70	71	72	73	74	74
Rokeby	26	24	24	24	23	23	23	23	23	22	22	22
Rosebery 22kV	5	4	4	4	4	4	4	4	4	4	4	4
Rosebery 44kV	16	19	19	19	20	20	20	20	20	20	20	20
Savage River	20	21	21	21	21	21	21	21	21	21	21	21
Scottsdale	15	15	15	15	15	15	15	15	15	15	15	15
Smithton	18	19	19	19	20	20	20	20	20	20	20	21
Sorell	22	22	23	23	23	24	24	24	24	25	25	25
St Marys	9	10	10	10	10	11	11	11	11	11	12	12
Temco	88	91	92	93	93	94	95	96	96	97	98	99
Trevallyn	119	129	131	134	135	137	138	140	142	143	145	147
Triabunna	4	4	4	4	5	5	5	5	5	5	5	5
Tungatinah	1	1	1	1	1	1	1	1	1	1	1	1
Ulverstone	33	32	32	33	33	34	34	35	35	35	36	36
Waddamana	0	0	0	0	0	0	0	0	0	0	0	0
Wayatinah	1	1	1	1	1	1	1	1	1	1	1	1
Wesley Vale	18	21	21	21	21	21	21	21	21	21	21	21

1.3 Generation

Tasmania currently has a total of 2513.4 MW of capacity installed comprising 28 hydro stations with a capacity of 2263MW , the Woolnorth wind farm with a capacity of 10.5MW and the gas/oil fired Bell Bay power station with a capacity of 240MW.

1.3.1 Typical Contribution to Peaks

Data on the contribution of each power station to the winter and summer peaks was not available so ACIL Tasman combined the typical flow data in Figures 6.7 and 6.8 of the 2002 Planning Report by the System Operator with coincident demands for the existing eight major generation injection points to estimate the percentage of plant capacity which is typically on line at winter and summer peak at these injection points. The results of this analysis are shown in Table 14.

Table 14 **Typical Usage of Plant Capacity at Summer and Winter Peaks**

Major Injection Point	Percent of Plant Capacity On Line at Winter Peak	Percent of Plant Capacity On Line at Summer Peak
Farrell	78%	30%
Sheffield	100%	42%
Palmerston	75%	100%
Derw ent 110kV	50%	47%
Derw ent 240kV	78%	109%
Trevallyn	75%	0%
Gordon	26%	92%
George Tow n	0%	0%

1.3.2 Forecast of Generation Capacity

The plant capacity is forecast to include the committed and advanced projects identified in the 2002 Planning Report which include:

- Conversion of Bell Bay to gas firing in 2003
- Stage 2 of the Woolnorth wind farm at 54.25MW to commence in 2003
- Butler's Gorge expansion by 2.4MW in 2003
- Forestry Tasmania's 30MW (export) Southwood plant fired on wood waste commencing in 2005
- Total Energy Services Tasmania's (TEST) 14.4MW plant fired on municipal waste and natural gas commencing in 2004
- Expansion of the Poatina hydro station by 45MW to commence in 2006

- Expansion of the Trevallyn hydro station by 16MW to commence in 2005

A forecast of total installed plant capacity in Tasmania at each major injection point, after adding in these developments, is shown in Table 15.

Table 15 **Forecast of Installed Plant Capacity at Major Injection Points (MW)**

Major Injection Point	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Farrell	626	626	626	626	626	626	626	626	626	626	626
Sheffield	319	373	373	373	373	373	373	373	373	373	373
Palmerston	302	302	302	302	347	347	347	347	347	347	347
Derwent 110kV	300	302	302	302	302	302	302	302	302	302	302
Derwent 240kV	215	215	215	215	215	215	215	215	215	215	215
Trevallyn	80	80	80	96	96	96	96	96	96	96	96
Gordon	432	432	432	432	432	432	432	432	432	432	432
George Town	240	240	240	240	240	240	240	240	240	240	240
Southwood	0	0	0	30	30	30	30	30	30	30	30
TEST	0	0	15	15	15	15	15	15	15	15	15
Total Tasmania	2513	2570	2584	2630	2675	2675	2675	2675	2675	2675	2675

1.3.3 Winter Peak Loading on Tasmanian Generators

The forecast generation at each major injection point to meet the forecast peak generated demand in Tasmania including Basslink is shown in Table 16. It has been assumed that the wind generators would not contribute to the system winter peak

Table 16 **Generation at Major Injection Points during the Winter Peak (MW)**

Major Injection Point	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Farrell	626	626	626	626	626	626	626	626	626	626	626
Sheffield	319	373	373	373	373	373	373	373	373	373	373
Palmerston	302	302	302	302	347	347	347	347	347	347	347
Derwent 110kV	300	302	302	302	302	302	302	302	302	302	302
Derwent 240kV	215	215	215	215	215	215	215	215	215	215	215
Trevallyn	80	80	80	96	96	96	96	96	96	96	96
Gordon	432	432	432	432	432	432	432	432	432	432	432
George Town	240	240	240	240	240	240	240	240	240	240	240
Southwood	0	0	0	30	30	30	30	30	30	30	30
TEST	0	0	15	15	15	15	15	15	15	15	15
Total Tasmania	2513	2570	2584	2630	2675	2675	2675	2675	2675	2675	2675

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