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Dear Mr Shivasabesan

TRANSEND'S REVENUE CAP APPLICATION TO THE ACCC

I am pleased to provide herewith my submission to assist the Australian Competition and Consumer Commission [ACCC] and interested parties in its consideration of Transend Network Pty Ltd's [Transend] application in respect of the revenue cap determination to be made by the ACCC.

This submission is to provide a background and context to the revenue cap for the regulatory period 1 January 2000 to 31 December 2003. It will assist all parties to better understand the background and matters that were considered when the Tasmanian Electricity Regulator [Regulator] made the determination that is about to expire. At that time, the Regulator was guided by the Tasmanian Electricity Code [TEC] which, in large part, replicated the National Electricity Code [NEC]. Nevertheless, the Regulator had a discretion in respect of the application of the TEC as well as noting that the NEC in the matter of network pricing was at that time undergoing review.

The revenue cap is intended to allow the entity to deliver a certain level of performance and assumes a capital and operating and maintenance program to ensure the delivery of the specified or agreed level of performance. This includes allowing for load growth, asset replacement and extension, and augmentation. Accordingly, it is relevant to provide a record of performance during the current regulatory period.

The performance record needs to be informed by an understanding of the electricity supply industry and changes during the relevant period. Accordingly, I have provided such a review, focused on the role of

Transend as the transmission network service provider [TNSP]. I also provide an overview of industry looking forward, and factors to be taken into account in considering the likely path of development. This includes regulatory changes as well as factors which will affect load growth and capital investment projections.

This information is to a large extent already in the public domain and is sourced from a variety of documents including:

- Planning Statements for 2001 and 2003 prepared by the System Controller;
- Electricity Supply Industry Price Determination, November 1999 issued by the Energy Regulator;
- Office of the Energy Regulator – Electricity Supply Industry Performance Reports for 2001 and 2002; and
- Reports by the Regulatory Reporter in respect of certain management plans required by the transmission licence.

The general approach taken has been to provide information to assist interested parties in understanding the context in which the current review is being undertaken by the ACCC as the responsible regulator. It is not the intention of the Tasmanian Energy Regulator to comment on the merits or otherwise of the Transend revenue cap submission.

Call for Submissions by the ACCC

The ACCC has released, since Transend made its revenue cap submission, a report prepared by consultant, Gutteridge Haskins and Davies [GHD]. This report considered Transend's proposed capital and operating budgets over the period 1 January 2004 to 30 June 2008. The ACCC has also met with interested parties and certain other matters have been raised in respect of the revenue cap application.

The following provides comment and information in respect of some of those matters.

Asset Management Processes

The consultant, GHD, expresses the view that Transend's asset management processes are technically focused, rather than risk management focused. The implication of this being that in some instances network development proposals may be technically, but not economically justified.

Transmission network developments since disaggregation of the electricity supply industry in July 1998 have been reviewed by the Reliability and Network Planning Panel [RNPP], which was established as an independent body in accordance with the TEC. The Regulator provided a 'regulatory test' substantially aligned with the 'regulatory test', applied by the ACCC. It is noted that the future role of the RNPP in the NEM has not been settled at this time.

There has been regulatory review in Tasmania of some elements of the future capital expenditure program proposed by Transend. This includes:

- Chapel St reactive support;
- Smithton – second circuit;
- North East transmission;
- Mowbray substation; and
- some parts of southern transmission.

There has not been a review of the forward capital program as a whole, or of other component parts of the proposed program.

The Regulator has required, through the transmission licence, that Transend develop and submit certain 'management plans' including an Asset Management Plan and a Service Plan. These have been independently reviewed and subject to discussion with Transend. The Regulator believes that Transend accepts that there should be a better alignment of asset management with the service plan which sets out the standards of performance and customer service levels to which Transend is bound through TEC requirements, connection agreements or has itself proposed.

To date, the Regulator has not issued any Guideline to Transend as to the expected form or content of these plans. The Regulator has concluded that it may be timely to consider such a guideline to assist Transend in refocusing its Asset Management Plan. This would be done in consultation with Transend and other interested parties.

Although this will not assist the ACCC in coming to a conclusion on what allowance should be made in relation to capital and maintenance expenditure on a ex ante basis, the existence of any such guideline will hopefully provide a framework for the ex-post review of capital expenditure at the next revenue reset. This should provide greater certainty for Transend that its processes are consistent with the regulatory framework and make its program more transparent and accessible at the time of review.

In regard to the ex-post review of capital expenditures undertaken during the forthcoming period, given the substantial increase in the proposed program, the history of underspending during the current period, and the time frame for the review, it may be prudent to consider a mid-term review and adjustment for any underspend. This would have the advantage of enabling any material underspend in the first half of the regulatory period to be shared with customers during the period. By bringing forward some of the adjustments to Transend's AARR, it should help to preserve Transend's cash flows in the following period. The Regulator has, during the current regulatory period, undertaken an annual review of capital expenditures. While this is an added administrative cost, it was considered warranted to protect and promote the interests of both customers and the entity.

The GHD report suggests that in the development of its revenue cap application 'its [Transend's] approach has not been sufficiently underpinned by adequate operation 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.'[1]

[1] GHD Transend Regulatory Review pii

These are matters which one would reasonably expect to be embedded in an integrated asset management, service standards maintenance and development, and business planning process.

This suggests that efficiencies in capital and operating expenditures could be gained through improved internal processes. This would be consistent with a revised approach to the integration of asset management with all relevant aspects of Transend's regulated operations. This revised approach could be driven by Transend, and/or supported by guidelines from the Regulator.

Planning approvals for Capital Expenditure

As discussed previously, Transend is, in some instances, required to seek local government planning and building approvals prior to undertaking new developments. These have, in the past, proved difficult and time consuming.

It may be appropriate that the ACCC as regulator gain an understanding as to what is required in relation to planning approvals for the projects that underpin the capital expenditure programs. This is consistent with the GHD observation that its recommended capex forecast does not allow for delays in external factors such as planning and environmental approvals.

There is some uncertainty as to network security standards in Tasmania as they have not been determined at a jurisdictional level. The initial intention was to consider this matter in the context of NEM security standards, but this has now reverted to being a jurisdictional responsibility. Transend is developing an approach to security standards, but this needs to be considered more widely and determined at a jurisdictional level. This work is in progress and will have an impact upon capex particularly and the application of the regulatory test, to the extent that investment to comply with standards is treated separately by the regulatory test.

Clawback of 2003 Expenditures

The approach at the jurisdictional level has been that the intention was to 'roll over' the existing determination with no clawback involved, other than the usual adjustments made for actual capital expenditure relative to the forecast capital program of the electricity entities.

In regard to the expected over or underspend of capital expenditure during the remainder of the current regulatory period, the Regulator would have adjusted, in the normal course of events, for the difference for the period 1 July 2002 to 30 June 2003 in the 2004 calendar year. Similarly the adjustment for the 2003-04 year would have been provided in the 2005 calendar year. I will endeavour to provide you with the relevant information for the period 1 July 2002 to 31 December 2003 as soon as possible.

Industry Structure

There is a little more complexity to the electricity supply industry than described by GHD, with the wind generator, Roaring 40's Pty Ltd, being a significant new entrant. It is noted that this entity is a wholly owned subsidiary of Hydro Tasmania.

Bell Bay Power Pty Ltd has also been established as a separate entity with responsibility for the operation of the Bell Bay thermal power station.

These and other developments in industry structure have been addressed in the accompanying submission.

Yours sincerely

Andrew Reeves
REGULATOR

August 2003

OFFICE OF THE TASMANIAN ENERGY REGULATOR

SUBMISSION TO ACCC

TRANSEND NETWORKS Pty Ltd

REVENUE CAP APPLICATION

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1 INTRODUCTION

1.1 Industry and Regulatory Background

The Tasmanian electricity supply industry (ESI) developed as a vertically integrated monopoly, similar to that in other Australian jurisdictions. Consistent with the National Competition Principles Agreement, Tasmanian commenced moving towards vertical disaggregation and independent regulation of the ESI with the *Electricity Supply Industry Act 1995* (ESI Act).

The ESI was disaggregated effective 1 July 1998 with separation of the *Hydro-Electric Corporation* (HEC). Generation remained with the HEC as a Government Business Enterprise, and the establishment of Transend Networks Pty Ltd (Transend), responsible for electricity transmission, and Aurora Energy Pty Ltd (Aurora) responsible for electricity distribution and retailing.

The ESI Act was amended in 1998 to provide for the establishment of an independent Regulator responsible for technical, safety and economic regulation of the industry[1]. This includes, where appropriate, price control of 'declared' electrical services (including electricity). The *Electricity Supply Industry (Price Control) Regulations 1998* (PC regulations) provide the regulatory framework for price or revenue control in respect of the relevant declared 'electrical services'. An electrical service may be made a declared service for the purposes of the PC Regulations if the Regulator is of the opinion that:

- the electricity entity has substantial market power in respect of that good or service; and
- the promotion of competition, efficiency or the public interest requires the making of the declaration.

The *Tasmanian Electricity Code* (TEC) came into effect on 1 July 1998. The TEC was intended to provide a comprehensive codification of technical requirements for the ESI. It was modelled in large part upon the *National Electricity Code* (NEC) to provide a transitional path to National Electricity Market (NEM) entry. In that respect it referred to, and, in part, replicated Chapter 6 of the NEC (Network pricing for Transmission and Distribution Systems). The PC regulations directed that the Regulator have regard to the TEC in that respect.

[1] Regulation of the safety of electrical infrastructure is addressed by the *Electricity Safety and Administration Act 1997*. The Regulator has delegated responsibility for administration and enforcement of this legislation to the Director of Industry Safety.

There had already been an independent investigation of the pricing of electricity and relevant electricity services in 1996, although at that time the relevant body, the Government Prices Oversight Commission (GPOC) made recommendations to the Minster, rather than a determination.

The independent Regulator, established by the ESI Act amendments of 1998, conducted an investigation and made a determination in respect of prices and revenue effective 1 January 2000 to 31 December 2002. This was consistent with what was, at that time, seen as the NEM entry timetable.

The State was concerned to ensure that the relevant regulatory arrangements were in place for an effective transition to the NEM. This included applying for 'jurisdictional derogations' to the NEC. These included passing regulation of transmission revenue to the Australian Competition and Consumer Commission (ACCC).

In recognition of the fact that some delays had developed in the NEM entry timetable, the derogations as finally approved, provided that the ACCC may undertake regulation of transmission revenue in accordance with Tasmanian law and the TEC. The condition imposed by the ACCC was that, upon NEM entry, the outcome of applying the TEC should not be materially different from the outcome provided by the NEC, in such circumstances the ACCC reserved the right to re-open the revenue determination.

The relevant law and other arrangements have now been made so as to confer upon the ACCC the authority to conduct the investigation of, and make a revenue cap determination in respect of, Transend's provision of transmission network services in Tasmania.

This determination is to be made effective 1 January 2004 and aligns with the commencement of the next regulatory period for other 'declared electrical services' in Tasmania. This notes that while the determination commencing 1 January 2000 was intended to expire on 31 December 2002, it was, by legislative amendment, extended until 31 December 2003.

1.2 Changes in the ESI since the 1999 Investigation

There has been some change to the underlying structure of the electricity supply industry in Tasmania since the 1999 Price Determination. Nevertheless, an effective monopoly in the provision of electrical services still exists at all levels of the industry, and customers have not, generally speaking, been able to offset this by recourse to alternative energy sources.

As part of the preparations for prospective NEM entry, Transend was appointed by regulation as system controller to provide system control services (ESI Act section 32)[2]. The System Control responsibility operates within a 'ringfence' in accordance with Chapter 11 of the TEC.

1.3 Prospective Changes over the Pricing Period

There are, however, a number of prospective changes that may impact on the Tasmanian Electricity Supply Industry (ESI) in the next five years. Of particular importance: the development of the natural gas project; the prospective development of Basslink; and Tasmania's participation in the NEM.

As a consequence of the introduction of natural gas, the Bell Bay Power Station is being progressively converted to gas. In addition, there are a number of other prospective new generation projects based on wind and alternative fuel sources.

1.3.1 Generation

Natural Gas and the redevelopment of Bell Bay Power Station

There have been significant developments in the scheme to bring natural gas to Tasmania by Duke Energy International (DEI). Ownership of Bell Bay Power Station (BBPS) has been transferred to a new company, Bell Bay Power Pty Ltd, a wholly owned subsidiary of the HEC. Unit one has been converted to be fired on natural gas. The second unit will be converted to gas in the near future.

Other proposed generation projects[3]

Wind resources on the west coast of Tasmania are being developed through a subsidiary corporate structure under the ownership of the HEC. Stage 1 of this project, which involves output from six turbines each with a capacity of 1.75 MW, has commenced production. The second stage of this project will comprise 31 wind turbines of 1.75 MW capacity. Stage 3 would involve a further 42 wind turbines which would bring the total installed capacity to 138.25 MW.

The HEC is also conducting a feasibility study in respect of wind energy prospects near Granville Harbour on the west coast, and at Musselroe Bay in the north-east of the State.

There are a number of other proposed generation projects including:

- Energy Equipment Pty Ltd (using wood waste) at Bell Bay;

---

[2] Hydro Tasmania was the System Controller at the time of the 1999 Price Determination. Transend was appointed as System Controller on 1 July 2000.

[3] Source - System Controller *2001 Planning Statement for the Tasmanian power system*, Transend, December 2001

- Total Energy Services Tasmania Pty Ltd (using municipal waste and supplementary gas firing) at Brighton; and
- Southwood (using wood waste) in the Huon Valley.

There is also proposed efficiency improvement and enhancement to existing hydro plant as well as some smaller turbine installations.

The expected total capacity of these projects is in the order of 65 MW. To date, generation licences have been granted to Energy Equipment Pty Ltd for development of a power station at Bell Bay and Bell Bay Power Pty Ltd and Roaring 40's Pty Ltd (wind development at Woolnorth and Bluff Point).

In addition, the natural gas development brings greater potential for other embedded generation and for co-generation to export to the grid or displace existing load.

1.3.2 Basslink

Basslink will profoundly affect the structure of the Tasmanian electricity supply industry. The Tasmanian Government proposes that Tasmania will become a region of the NEM with electricity generation dispatched through supply side bids in the electricity 'pool'[4.]

The Government's submission to the ACCC, seeking authorisation of certain aspects of the proposed arrangements for Tasmania's participation in the NEM, states that access to import rights over Basslink will be sold, thereby facilitating diversity of supply and competition at the retail level in Tasmania. This has now been supported by legislative powers in amendment to the ESI Act.

There has been considerable investment in Basslink in terms of planning and addressing regulatory issues. The relevant development contract was signed in November 2002 and it is now a committed project.

1.3.3 Prospective Regulatory and Other Changes Post NEM Entry

The Tasmanian Government has made provision through the *Electricity – National Scheme (Tasmania) Act 1999* for the application of the *National Electricity Law* (NEL) in Tasmania. The date of commencement of the NEL (which gives effect in Tasmania to the NEC) is referred to as 'NEM entry'. The prospect of Tasmania's entry into the NEM requires considerable preparation to bring the Tasmanian electricity industry into line with the standards, practices and procedures of the national market. The Government's preparation for NEM entry includes obtaining authorisation from the ACCC for various proposed transitional arrangements.

In the NEM, wholesale electricity prices are set through the generation market, except to the extent that there is a vesting contract in relation to electricity supply to

[4] The pool notionally takes account of demand side bids to set the marginal price, but at this time demand side bidding is underdeveloped.

Aurora, for supply to non-contestable customers. As part of the preparations for NEM entry, the Tasmanian Government submitted the vesting contract between HEC and Aurora for consideration by the ACCC. This vesting contract will take effect on NEM entry and will set the contract price between the two entities for between 75 and 90 per cent of the energy requirement to meet the non-contestable load[5].

It also submitted certain technical derogations for consideration by the ACCC, eg frequency standards and fault clearance times.

1.3.4 The NEC and the role of the ACCC and Jurisdictional Regulator

Once Tasmania joins the NEM, participants will be required to comply with the provisions of the NEL and the NEC, except to the extent that the Tasmanian derogations have been granted. In making application for authorisation of the derogations, the Government noted:

> The main purpose of the Tasmanian derogations is to provide continuity and assist the transition to the arrangements under the Code from State arrangements and price determinations established prior to Tasmania's entry to the NEM, principally under the ESI Act and the TEC (Tasmanian Electricity Code). As such, the derogations have regard to the legitimate interests of participants and consumers by providing certainty during the transition period.
>
> The derogations provide, amongst other things, for:
>
> (a) provision for regulation of transmission service revenues and pricing in the transitional period and recognition of the value of Transend's existing asset base (to be set by the Minister), minimising any potential discontinuity of the price arrangements for network owners and customers, relative to the pricing arrangements currently in place in Tasmania;
>
> (b) provision for regulation of distribution service pricing by the Jurisdictional Regulator for the transitional period, enabling continuity of pricing arrangements for distribution network owners and certainty for pricing arrangements already established in Tasmania;
>
> (c) appointment of the ACCC as the Jurisdictional Regulator responsible for transmission pricing and the Regulator appointed under the ESI Act as the Jurisdictional Regulator responsible for distribution pricing in accordance with the requirements of chapter 6 of the Code.

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[5] ACCC Authorisation required that the vesting contract be amended 'by reducing the volume coverage to 90 per cent of the non-contestable load from the commencement of Basslink commercial operations and providing that Aurora must have an option to reduce this down to a minimum of 75 per cent of the non-contestable load.' However, once Aurora has exercised its option to reduce coverage, it should not have an option to increase above that level at a later date (ACCC Authorisation Decision p49).

Under the NEC, the determination of the revenue cap for the provision of transmission services is carried out by the ACCC. Economic regulation of distribution network services and retail tariffs (where applicable) remains the responsibility of the Jurisdictional Regulator. Under Tasmania's derogation, regulation of distribution service revenues and pricing in Tasmania will be carried out in accordance with the Tasmanian regulatory regime (ESI Act, PC regulations and the TEC) in the transitional period, to the exclusion of the NEC. The transitional period for distribution pricing covers the period up until the end of the second tranche of contestability.

1.3.5 Retail Contestability

The retailing of electricity is the subject of an exclusive retail franchise held by Aurora. This exclusive franchise will continue until the government makes regulations providing for 'contestable' customers. The exclusive franchise will continue for those classes of customer that are not made 'contestable' by regulation.

The Tasmanian government proposes to introduce contestability progressively, commencing six months after Basslink comes into service. The November 2001 ACCC Determination in relation to Tasmanian Derogations and Vesting Contract[6], suggested that Basslink was expected to be in service at end 2003. The revised contestability as advised by the government is as set out below. This assumes a commencement of NEM prior to Basslink operational commissioning, with contestability commencing 6 months after commissioning.

Table 1.1: Indicative Contestability Timetable

	Commencement (assumed NEM May 2005)	Expected Date	Contestability Limit	Approximate additional uncontracted customers
Tranche 1	6 months	1 July 2006	20 GWh/yr	10
Tranche 2	18 months	1 July 2007	4 GWh/yr	54
Tranche 3	30 months	1 July 2008	0.75 GWh/yr	295
Tranche 4	42 months	1 July 2009	0.15 GWh/yr	1 030
Full Retail Contestability	54 months	1 July 2010	Under 0.15 GWh/yr	230 000

Source: Department of Treasury and Finance

The State has advised that the Regulator will retain responsibility for the regulation of non-contestable customer tariffs during the rollout of contestability.

[6] ACCC, *Applications for Authorisation: Tasmanian Derogations and Vesting Contract, Tasmania's NEM entry - Final Determination*, 14 November 2001, p33.

2 REVENUE CAP DETERMINATION FOR TRANSEND – REGULATORY PERIOD 1 JANUARY 2001 TO 31 DECEMBER 2003

2.1 Introduction

The following information is provided to assist the ACCC in understanding the background to the existing transmission revenue cap and other related industry arrangements. The methodology adopted by the Regulator, in establishing Transend's regulated asset base, capital expenditure and operating and maintenance (O&M) expenditure for the regulatory period commencing 1 January 2000, is relevant to understanding the impact of the revenue cap to be made by the ACCC.

The information is extracted from the *Investigation into Electricity Supply Industry Pricing Policies, Final Report and Determination of Maximum Prices - November 1999*. Also provided is a comparison of forecast and actual outcomes with respect to capital and O&M expenditure extracted from Transend's annual statement of compliance with the Regulator's 1999 Determination.

2.2 Relevant Aspects of Current Determination

2.2.1 The Asset Base

In considering the approach to adopt in setting a value for the regulated asset base for Transend for the regulatory period commencing 1 January 2000, the Regulator had three options:

- roll forward the value of the assets attributable to Transend from the 1996 HEC valuation;
- undertake an independent valuation; or
- accept Transend's book values based on an internal revaluation.

The methodology used by the Regulator involved:

- an independent valuation based on Australia wide benchmarked data, and adjusted for local conditions which was preferred to one undertaken by the entity; and
- taking the depreciated optimised replacement cost (DORC) as the upper limit.

Sinclair Knight Merz (SKM) had been engaged by GPOC in May 1998, to undertake a valuation of the transmission and distribution assets prior to disaggregation. SKM was requested to value the assets on a 'consolidated aggregate DORC basis' attributable to the transmission and distribution activities of the HEC. The initial draft report was completed in July 1998.

Following disaggregation of the HEC into the three businesses, HEC (Hydro Tasmania), Transend Networks Pty Ltd (Transend) and Aurora Energy Pty Ltd (Aurora), the report was revised to separately report on the transmission and distribution assets that were attributed to Transend and Aurora.

The revised draft report on the valuation of transmission assets was provided to Transend and the Regulator in March 1999.[7] SKM concluded its discussions with Transend and issued the final report on the valuation of transmission assets in mid 1999. A copy of both reports is available on the website for the Tasmanian Energy Regulator at www.energyregulator.tas.gov.au.

SKM, in its asset valuation reports, stated that it 'has applied the DORC methodology applying in other States, taking into account local factors'. Specific reference was made to the NSW Asset Valuation Guidelines applied to transmission and distribution assets in that state.[8]

In undertaking any revaluation, the Regulator considered that the following issues warranted consideration.

2.2.1.1 Treatment of Wholesale Sales Tax (WST)

Government Business Enterprises, including the former HEC and new Hydro Tasmania, and State-owned companies including Transend and Aurora, were subject to a Wholesale Sales Tax Equivalent (WSTE) regime[9] under State statute.[10] The acquisition (either through purchase or construction) of transmission and distribution assets by the former integrated HEC was exempt from WSTE on the basis that the generation and transformation of electricity and the intermediate transportation of electricity was part of a manufacturing process.

Following disaggregation, the argument to treat the transformation and transport as part of the manufacturing process, through the transmission and distribution networks, was less compelling. The view adopted was that these activities are in the nature of 'packaging and transport' not 'manufacture' under the definition in the relevant Tax Acts.

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[7] Sinclair, Knight Merz, *Valuation of Transend's Asset Base*, March 1999.

[8] NSW Treasury, *Policy Guidelines for Valuation of Network Assets of Electricity Network Businesses*, December 1995.

[9] It should be noted that the WSTE regime ceased when it was replaced by, the Commonwealth's goods and services tax (GST) regime implemented in July 2000. The potential impacts of GST are discussed in Chapter 1 of the Draft Report.

[10] The HEC is required to pay WST equivalent under Part 10 of the *Government Business Enterprises Act 1995* (GBE Act). Transend and Aurora are required to pay WST equivalent under the *Electricity Companies Act 1998* in accordance with Part 10 of the GBE Act.

The Regulator concluded that inclusion of WSTE in the asset base in relation to pre-disaggregation assets on which no WSTE was paid would provide the two network service providers (NSPs) with an effective 'windfall gain'. That is, in doing so they would be provided with a rate of return on expenditure that had not been incurred nor would be required to be paid on replacement assets.

The Regulator considered, on balance, that WSTE should not be included in the asset base for pre-disaggregation assets. As WSTE was a real cost in the post-disaggregation period, WSTE was allowed for the period 1 July 1998-30 June 2000.[11] Thus the post June 1998 asset values and capital expenditure estimates used in the 1999 Determination included a WSTE component. It should be noted, however, that the Determination provided for an adjustment to be made to Transend's revenues for the net impact of the Commonwealth's New Tax Package. Thus actual asset values post 1 July 2000 are exclusive of WSTE.

2.2.1.2 Interest during Construction (IDC)

The SKM valuations excluded the cost of IDC. However, the Regulator concluded that as this was, and is, a real cost of any large development and is recognised by Australian Accounting Standards. The Regulator included an allowance for IDC. For pre-disaggregation assets the SKM estimates were used.

For assets brought into service post 1 July 1998 an IDC of 5 per cent was provided.

2.2.1.3 Timing

The Regulator decided, in principle, that the amount included in the SKM valuation for work-in-progress as at 30 June 1998, would not be included in the 30 June 1998 valuation, with the total agreed value of the capital project rolled into the asset base from the date of commissioning of the relevant asset.

This treatment was consistent with the in-principle treatment of new assets purchased or constructed during the regulatory period.

2.2.1.4 Exclusions from the Asset Base

The Regulator considered it inappropriate to allow the entities to earn a rate of return on assets for which customers had made a direct contribution. On this basis, customer capital contributions were excluded from the regulatory asset base.

In addition, the Regulator decided that assets not used in the generation of revenues from tariff customers should be excluded from the regulated asset base. At that time there were no assets used exclusively for non-transmission purposes. Non-regulated activities were an immaterial component of total activities and any use of regulated assets for unregulated revenue generation was immaterial.

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[11] The GST regime commenced on 1 July 2000.

2.2.1.5 Wayleaves

In relation to way-leaves, the Regulator concluded that the indexed historic cost was the most appropriate method for valuing these assets as it recognises the financial investment made in these assets. The use of market values as an estimate of indexed historic cost was not appropriate where there had been significant changes in land usage and thus market purchase prices for such land would have risen faster that the CPI. These assets exist in perpetuity and as such will not need to be replaced.

Further, the easements have diminished value in the market place if no longer required by Transend. That is, in effect, there exists a differential between the market buying price and the market-selling price for Transend for easements. The methodology adopted by Transend to calculate the value of easements was to:

- initially asses the market value (purchase price) of each category of land (bush and undeveloped rural, improved rural, inglobo and residential);
- using a small sample of easements (with known historical values) compare the market values of these easements with the known indexed historical cost to provide an adjustment factor (30 per cent); and
- deflate the total market values by the adjustment factor.

The Regulator examined the methodology and the resulting outcomes and considered that an adjustment factor in the order of 50 per cent would be more appropriate and would better reflect the differential between market value and indexed historical cost over the preceding 40-year period (the average life of transmission assets).

In relation to the valuation of way-leaves for Transend, the Regulator also noted that the Government supported the use of the estimate of the way-leaves provided by Transend, ie $17 million compared to the upper limit estimate of $28 million.

SKM had in its recommendations to the Regulator valued wayleaves at $5 million, $12 million less than the minimum that Transend considered it would accept.

After considering the information contained in the SKM Report, all submissions and the Office's own analysis, the Regulator concluded that he would allow an adjustment of $4 million over the SKM recommendation, ie a final allowance of $9 million was provided.

2.2.1.6 Comparison with the Roll-forward values

The roll-forward of the GPOC values for Transend exceeded the DORC values assessed by SKM. As the Regulator was of the view that the DORC should be the upper limit and that an independent valuation is more appropriate than an entity assessed value, the Regulator accepted SKM valuations.

2.2.1.7 SKM Valuations

SKM applied the DORC methodology, taking into account local factors. Based on this methodology, SKM estimated the DORC value of the transmission assets controlled by Transend as at 30 June 1998 to be $343.3 million including IDC but excluding WSTE.

Table 2.1: SKM Transend Asset Valuation 1 July 1998 ($'000 June 1998)

Description	Replacement Cost	Optimised Replacement Cost	Depreciated Optimised Replacement Cost	Annual Depreciation
Operational (network) assets excl WIP, inc IDC	754 365	738 945	323 185	12 762
Non-operational assets			3 718	
Capital Liabilities (est)			(5 000)	
Work in progress			21 354	
Total			**343 257**	**12 762**

Source: Sinclair Knight Merz Report, July 1999

The main points to note from the SKM Report were:

- The replacement costs were based on the required service potential and output consistent with both the future growth in demand and the minimisation of whole of life costs.
- The approach to optimisation was on an 'incremental' basis which recognised the historical development of the existing business, the time lag in asset planning and construction, and the long asset lives. The key elements included:
  - use of modern equivalent assets,
  - identification of redundant, grossly oversized or over-capacity assets and replacement for valuation purposes with assets of appropriate rating and design,
  - in assessing over-capacity, account was taken of proper whole of life economic considerations,
  - in assessing redundant assets, account was taken of the specific reliability and security requirements required in the network, and
  - IDC was included in recognition that it was a real cost in large developments.
- Average unit costs were based on long-term (based on past five to 10 years) average unit costs of modern equivalent assets for each asset class.
- The standard useful lives applied were generally consistent with those assigned in other states. However, assets whose age exceeded the respective standard useful life and which were still operational, were assigned a useful life of five years.

- Local conditions such as climatic conditions, terrain, special transport factors and local labour costs were taken into account in determining average unit costs. However, the average unit costs were also based on an assumption of appropriate competitive tendering practices and efficient planning and project management techniques.

  - WST (or equivalent) was not incorporated in the costings.

Transend supported the use of DORC for the valuation of the asset base. However, Transend, in its July submission, stated it was of the view that the valuation provided by SKM should be adjusted upwards to a total of $442.46 million (as at 1 July 1998).

The main issues of disagreement between SKM and Transend relate to WST, the cost of substation establishment costs, way-leave valuation and capital liabilities.

Transend was of the view that:

- WSTE is a real cost to Transend (from 1 July 1998) in undertaking its capital expenditure program, and thus it should be factored into the replacement cost of its asset base including assets acquired pre 1 July 1998.

- SKM had undervalued site establishment costs and project management costs for substations. For example, the costs of building the new Hadspen substation exceeded the value based on SKM's methodology by approximately $4.5 million.

- Way-leaves were substantially undervalued by SKM ($5.0 million) and Transend contended that the value of these at 1 July 1998 was in the order of $17 million to $28 million. In the July 1999 submission Transend noted that it was willing to accept the more conservative estimate of $17 million as an appropriate valuation.

- The majority of items included in the category 'capital liabilities' should not have been included in the valuation. Transend was of the view that the only item that could be validly included was an adjustment for oil bunding costs in relation to three substations – and this should have been adjusted against the value of the three substations directly. The effect of including all these items was to reduce the total value of the assets. These should have been more appropriately classified as costs and as such included in operating and maintenance costs.

Transend, in the covering letter to its July 1999 submission, also noted that an issue arising late in the valuation process was the ownership of certain SCADA equipment. Initially, Transend understood that these assets belonged to the HEC and were not included in the asset set provided to SKM for valuation purposes. Transend estimated that these assets were valued at approximately $8 million. These assets, therefore, were not included in the SKM asset valuation report, but were added to the Regulatory asset base on a go-forward basis.

A summary of the key differences between SKM's valuation and Transend's estimates of the assets actually valued by SKM, by category is shown in Table 2.2:

Table 2.2: Transend's Proposed Asset Valuation adjustments July 1998

Issue	Variation $m
Substation	33.6
WSTE	44.3
Way-leaves (based on Transend's conservative estimate of $17 million)	12.0
Capital Liabilities	8.3
Working Capital	1.0
Total	**99.2**

Source: Transend, Transmission Pricing – Second Submission, July 1999

2.2.2 Asset Base 1 July 1998: Summary

In summary, the following adjustments were made to the SKM recommended valuations:

WSTE:

– was not included in the valuation of the asset base for assets acquired prior to 1 July 1998;

– paid on capital expenditure from 1 July 1998 to 31 December 1999 was included;

– was provided for on assets brought into service during the regulatory period (ie 1 January 2000 to 31 December 2002);

work-in-progress - was excluded from the 1 July 1998 asset base;

capital expenditure - was to be brought into the asset base from the date of commissioning of the asset;

capital contributions from customers - was deducted from the asset base on the basis that it was considered inappropriate for Transend to earn a rate of return on assets that did not require a capital outlay by the entity;

wayleaves - an adjustment of $4 million was made to the SKM valuation of wayleaves (ie to give a total value of wayleaves of $9 million); and

SCADA assets - of $8 million have been included in the regulatory asset base.

Table 2.3: Transend Regulatory Asset Base 1 July 1998 ($m July 1998)

Description	Replacement Cost	Optimised Replacement Cost	Depreciated Optimised Replacement Cost	Annual Depreciation
Operational (network) assets excl WIP, inc IDC and including additional $4 million for wayleaves	758.37	742.95	327.19	12.76
Non-operational assets			3.72	
Capital Liabilities (est)			(5.0)	
Customer contributions			(1.7)	(0.03)
Working capital			1.00	
Add SCADA assets			8.05	0.77
Total			**333.25**	**13.50**

Source: Office of the Tasmanian Regulator: 1999 Final Report

In reaching this decision, the Regulator took particular note of Transend's arguments in regard to the valuation of physical assets and in regard to the valuation of easements.

If the DORC methodology was rigorously applied, there may have been a case for a higher valuation of easements to better reflect costs which would be faced by a full replication of existing assets. However, in conducting the DORC valuation, there are a number of assumptions made which over-stated costs of providing the same service. That is, the valuation is in regard to the assets, rather than in regard to the service, and is based on 'brownfields' costs rather than 'greenfields' costs. Further, the DORC is the upper limit of the range that the Regulator may adopt.

2.2.3 Roll-Forward of the Asset Base during the Regulatory Period

The key issue in rolling forward the asset base was consideration of the appropriate timing for the inclusion of new capital expenditure. The two options considered were:

- the inclusion of the estimated expenditure as it is incurred with no IDC allowed; and
- the inclusion of capital at the time the asset is brought into service, with an allowance for IDC.

The second option was adopted for Transend's capital expenditure for the calculation of the roll-forward asset values.

Another issue considered was the potential for the actual capital expenditure to be less than the projected capital expenditure in any one year and over the regulatory period. On this basis, in rolling forward the asset base the Regulator made an adjustment to the forecast completion of assets to recognise the potential for delays in the capital expenditure program for Transend. The Regulator used a factor of 90 per cent of the capital forecasts to calculate the asset roll-forward for the regulatory period for Transend.

It was recognised that the estimate of expenditure would be reviewed in the light of any recommendations made during the regulatory period by the Reliability and Network Planning Panel (RNPP). That is, in addition to the in-period adjustment for under and/or over expenditure, there would also be a prudency review of all capital expenditure, with the potential for the AARR to be adjusted if necessary.

2.2.4 Capital Expenditure during the Regulatory Period

Transend was planning a capital expenditure program estimated at that time to be around $448 million over the next decade. The stated objectives of the program were to:

- improve reliability by providing a more robust network and upgrading protection systems;
- replace assets which have reached the end of their service lives; and
- increase capacity to meet growth in demand for electricity.

Transend estimated that the value of capital works to be brought into service during the regulatory period would be approximately $52.5 million in 1999-2000, rising to approximately $60.5 million in 2001-02 including WSTE.

Table 2.4: Forecast capital expenditure (including WSTE allowance) ($m June 1999)

Year	Forecast Expenditure	Total Assets brought into Service	Capex Dedicated to Specific Customers
1998-99	55.60	57.56	
1999-00	45.00	52.54	
2000-01	61.20	47.93	
2001-02	59.00	59.40	1.00
2002-03	60.00	46.08	
Sub-total	**280.80**	**263.52**	**1.00**

Year	Forecast Expenditure	Total Assets brought into Service	Capex Dedicated to Specific Customers
2003-04	55.20		
2004-05	24.80		
2005-06	19.50		
2006-07	22.50		
2007-08	33.20		
2008-09	12.30		
Total	**448.30**		**1.00**

Source: Transend Issues Paper, April 1999

2.2.5 Roll-Forward of Asset Valuations – Conclusion

In order to calculate the value of the regulatory asset base at the commencement of the regulatory period (ie 1 January 2000), the asset values as at 1 July 1998 were adjusted to 1 January 2000 values plus net additions to the asset base from 1 July 1998 to 31 December 1999 were also incorporated. Assets due to be brought into service during the regulatory period, were added to the regulatory base in the year that they were due to be commissioned. Likewise assets have been removed from the asset base during the year of decommissioning.

For the purpose of the Determination of November 1999, the assumptions used in calculating the roll forward asset values were:

- the opening values as at 1 July 1998 were based on the SKM DORC valuation adjusted for work-in-progress, customer capital contributions, working capital, IDC, wayleaves and additional SCADA assets;
- SKM values for depreciation adjusted for depreciation associated with SCADA assets and assets provided by customer contributions were used;
- Transend's forward capital asset addition estimates were adjusted to 90 per cent of the value of assets;
- for assets brought into service post 1 July 1998, all WSTE paid was included in the asset values;
- IDC at 5 per cent was incorporated in capital expenditure brought into service post 1 July 1998; and
- CPI adjustments were made to the asset base, asset disposals made during the period 1 July 1998 to 30 December 1999 and depreciation for the same period.

Table 2.5: Roll forward of Asset Values ($m July 1998)

Year	Details	Adjustments	Total
1 July 1998 – 30 June 1999	**Opening Assets**		**333.25**
	Add Assets bought into Service	59.60	
	Less Depreciation	14.49	
	Less Disposals		
1 July 1999 – 30 June 2000	**Opening Assets**		**378.37**
	Add Assets bought into Service	48.00	
	Less Depreciation	15.21	
	Less Disposals	4.83	
1 July 2000 – 30 June 2001	**Opening Assets**		**406.33**
	Add Assets bought into Service	42.90	
	Less Depreciation	15.93	
	Less Disposals		
1 July 2001 – 30 June 2002	**Opening Assets**		**433.33**
	Add Assets bought into Service	52.20	
	Less Depreciation	16.80	
	Less Disposals		
30 June 2002	**Closing Assets**		**468.71**

Source: Office of the Tasmanian Energy Regulator: Final Report 1999

For the calculation of the AARR for each calendar year of the regulatory period, the value at 1 July of each year has been adopted.

2.2.6 Operating and Maintenance Expenditure

The allowance for operating and maintenance costs provided in the determination was based on the entities' budgeted expenditure less a margin for anticipated productivity gains, taking into account a number of benchmark figures for similar entities. The rationale for this was to ensure that the consumer did not pay for inefficiencies in the organisation, and to provide a mechanism by which the consumers share in the benefits of productivity gains during the regulatory period.

A benchmarking study was undertaken by the UMS Group during 1998. This study indicated that Transend could achieve substantial efficiency gains in the area of operations and maintenance. However, on examination of the detail of the UMS Report, the Regulator formed the view that the study did not provide a sufficiently robust assessment of the potential for efficiency savings into the future given the changed activity base for Transend.

Comparison with GPOC Assessment of O&M

The Regulator also examined the cost movements in network operations and maintenance expenditures over the period since the 1996 GPOC investigation was finalised. GPOC estimates for operations and maintenance expenditure for the HEC were based on the 1994-95 financial year outcomes. A high level assessment of the transmission and distribution outcomes was also made.

The 1999-2000 budget for Transend's operating and maintenance expenditure, including corporate overheads and regulatory compliance costs, but excluding System Control costs, was $15.60 million. This represented an apparent decline in efficiency of approximately 18.5 per cent. However, this issue is complex and the Regulator is aware that the increase in expenditure may have been a result of a number of factors, for example:

- A change in activity level, with a substantial increase in transmission operational and maintenance activity and a reduction in distribution operational and maintenance activity. This may have reflected under-spending on transmission operations and maintenance in 1994-95 with the increase in 1998-99 and 1999-2000 financial years partly attributable to an accrued backlog of work. Transend supported this view in its response to the Draft Report where it stated that a 1997 benchmarking study indicated that in some areas the system was being under-maintained. Transend also noted that this was being addressed.

- A change in the allocation of assets, such as switchyard equipment, between generation and transmission resulting in increased maintenance costs.

- An increase in charges that Transend incurred as a result of disaggregation, with Transend purchasing services from the HEC and from Aurora Services at rates significantly higher than the internal rates that underlie the 1994-95 ring-fenced accounts. It is also noted that Transend was required, at the time the Final Report was prepared, to pay for certain functions undertaken by System Control on its behalf. These costs totalled approximately $2.55 million in 1999-2000 and $3.1 million in each of the two following years (in 2000 dollar terms).

- A change in allocation of costs between transmission and distribution. However, this was unlikely to have contributed to the difference to any significant degree.

Transend also noted that additional costs incurred by the allocation of pre-disaggregation HEC corporate costs, plus additional corporate and regulatory compliance costs, would total some $2.7 million.

Transend in its response to the Draft Report also stated that it was assigned assets that were formally managed by the Generation Division of the aggregated HEC. Transend noted that the majority of these assets were in the highest age quarter of Transend's assets and as such require additional maintenance. In addition to these assets, Transend had created Hadspen Substation and Liapootah - Palmerston 220 kV transmission line. The inclusion of additional assets had an impact on the required level of operations and maintenance expenditure post disaggregation.

Operations and Maintenance - Conclusion

The Regulator decided to apply a reduction of approximately nine per cent over the three years of the pricing period from 1 January 2000, from the 1999-2000 budget base of $15.25 million (excluding System Control costs). That is, a nine per cent target for Transend was applied to the operations and maintenance costs excluding costs associated with System Control. Transend's target operations and maintenance expenditures for the three years are detailed in Table 2.6.

Table 2.6:Transend Operating and Maintenance Expenditure (June 1999$)

	1994-95 HEC	1999-2000	2000-01	2001-02
	$m	$m	$m	$m
Total Operational Expenditure Budget	12.87	17.75	18.34	18.32
System Control Budgeted Costs		2.50	3.04	3.04
Operations and Maintenance (excluding System Control costs)		15.25		
Productivity Factor applied to Operations and Maintenance excluding System control costs		-3%	-3%	-3%
Cumulative Productivity		-3%	-5.9%	-8.7%
Allowable Operations and Maintenance (excluding System Control)		14.80	14.35	13.92
Total Allowable Operational Expenditure (including System Control Costs)		17.30	17.39	16.96

Note: (1): It should be noted that since disaggregation, Transend has incurred additional costs associated with disaggregation and increased operations and maintenance costs associated with assets transferred to Transend that were previously the responsibility of the Generation Division of the HEC. Transend has estimated that these two factors have increased Operations and Maintenance costs by approximately $2.8 million per annum.

2.2.7 Annual Aggregate Revenue Requirement

For assessment of the AARR, the simple average of the financial year allowances was adopted.

2.2.8 Comparison of forecast and actual outcomes

As can be seen from Table 2.7 Transend has consistently spent at levels higher than the allowances made in the 1999 Determination. Of particular note is the $3.4 million variation in 2001-02. As there was no mechanism to clawback the difference Transend has been required to absorb the differences.

Table 2.7: Operating and Maintenance Expenditure Variances

	1999-00 $'000	2000-01 $'000	2001-02 $'000
Forecast	17 910	17 900	17 950
Actual	19 683	19 657	21 314
Variance	1 773	1 757	3 364

Source: Transend, information provided for the 2002 Performance Report

Note: the figures provided are based on the financial year although the Determination was made on a calendar year basis.

In relation to capital expenditure, Transend has consistently spent below the forecast amounts. As noted above, the forecast was based on 90 per cent of Transend's budget. As the Determination provided for a clawback mechanism the revenues were adjusted on an ex poste basis for the difference between the previous year's actual and forecast. As can be seen from Table 2.8 the variance has increased steadily over the period with a variation (underspend) of nearly $23 million in 2001-02

Table 2.8: Capital Expenditure Variances

	1998-99 $'000	1999-00 $'000	2000-01 $'000	2001-02 $'000
Forecast	60 441	49 521	45 706	57 481
Actual	56 985	40 953	29 705	34 511
Variance	(3 456)	(8 568)	(16 001)	(22 970)

Note: the figures provided are based on the financial year although the Determination was made on a calendar year basis.

Source: Transend Revenue Cap Compliance Statement

3 TRANSMISSION NETWORK AND TECHNICAL PERFORMANCE

3.1 Overview of Transmission Network

Transend owns 3 516 km of transmission lines of which 1 464 km are at 220 kV, 1972 at 110 kV and 81 km at 88 kV. The total route length is 2 342 km. Transend owns 7 982 towers and maintains 10 500 ha of easements across Tasmania.

Transend owns 45 substations and 10 switching stations. Eleven substations (both substations and switching stations) operate at 220 kV, 42 operate at 110 kV or below and two at 88 kV or below. There are 109 transformers and 757 circuit breakers.

An overview of the transmission system is presented in figure 3.1 with a schematic representation of the network in figure 3.2.

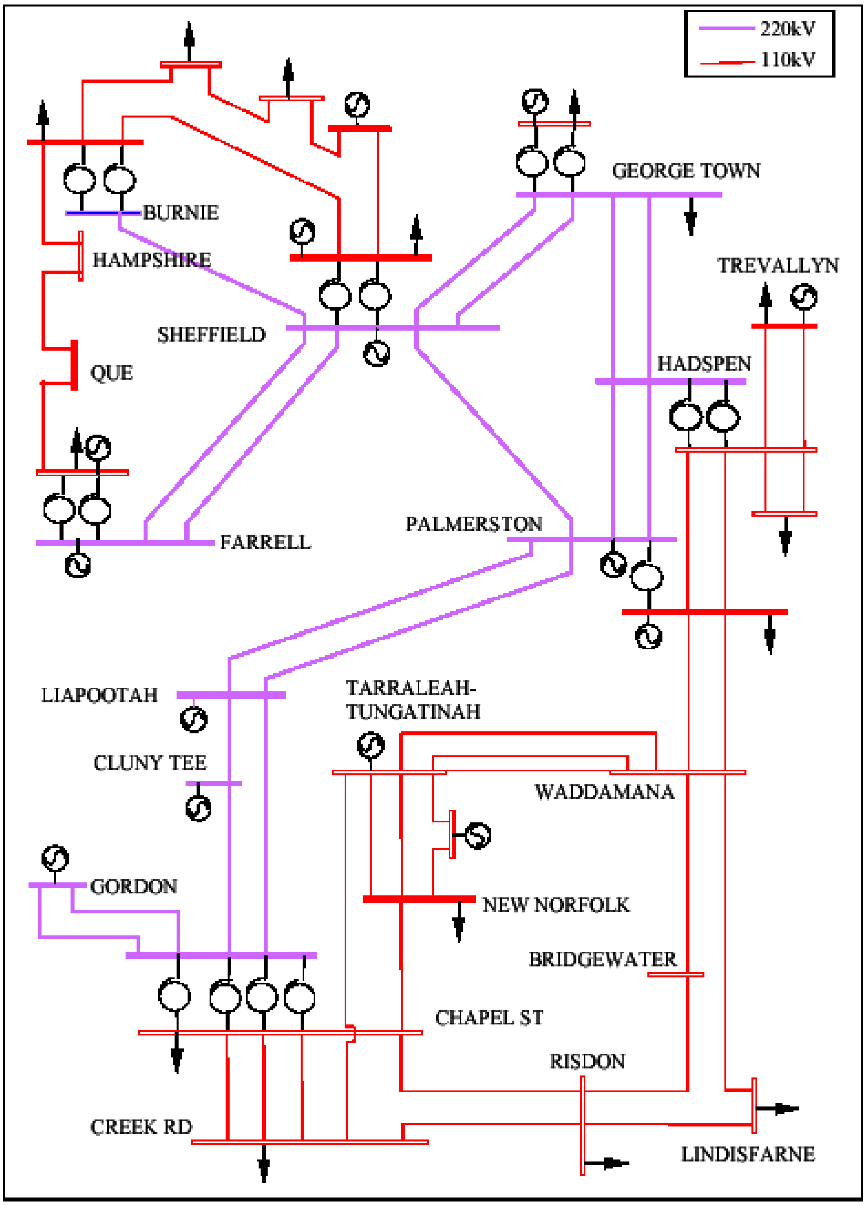
Diagrammatic representations of typical peak-loads are given in figure 3.3 (winter) and figure 3.4 (summer). Typically, winter flows are from the minor storages and hence from north to south. If the values in the darker grey boxes for each transmission line exceed the values shown in the light grey boxes then a transmission constraint is likely.

In winter there can be transmission constraints to power flow from Farrell to Sheffield and constraint on transformation capability at Chapel Street to feed the southern load.

During the summer months (from December to April), there is less generation available from run-of-river stations and greater reliance is placed on the larger and medium storages. Therefore in summer typical flows are from south to north. It is important to note that the capacity limits for the transmission lines also reduce during summer due to the higher ambient temperatures. Constraints that are likely to apply during the summer include Palmerston to Sheffield and Hadspen, and from Derwent to the southern load along the 110 kV transmission corridor.

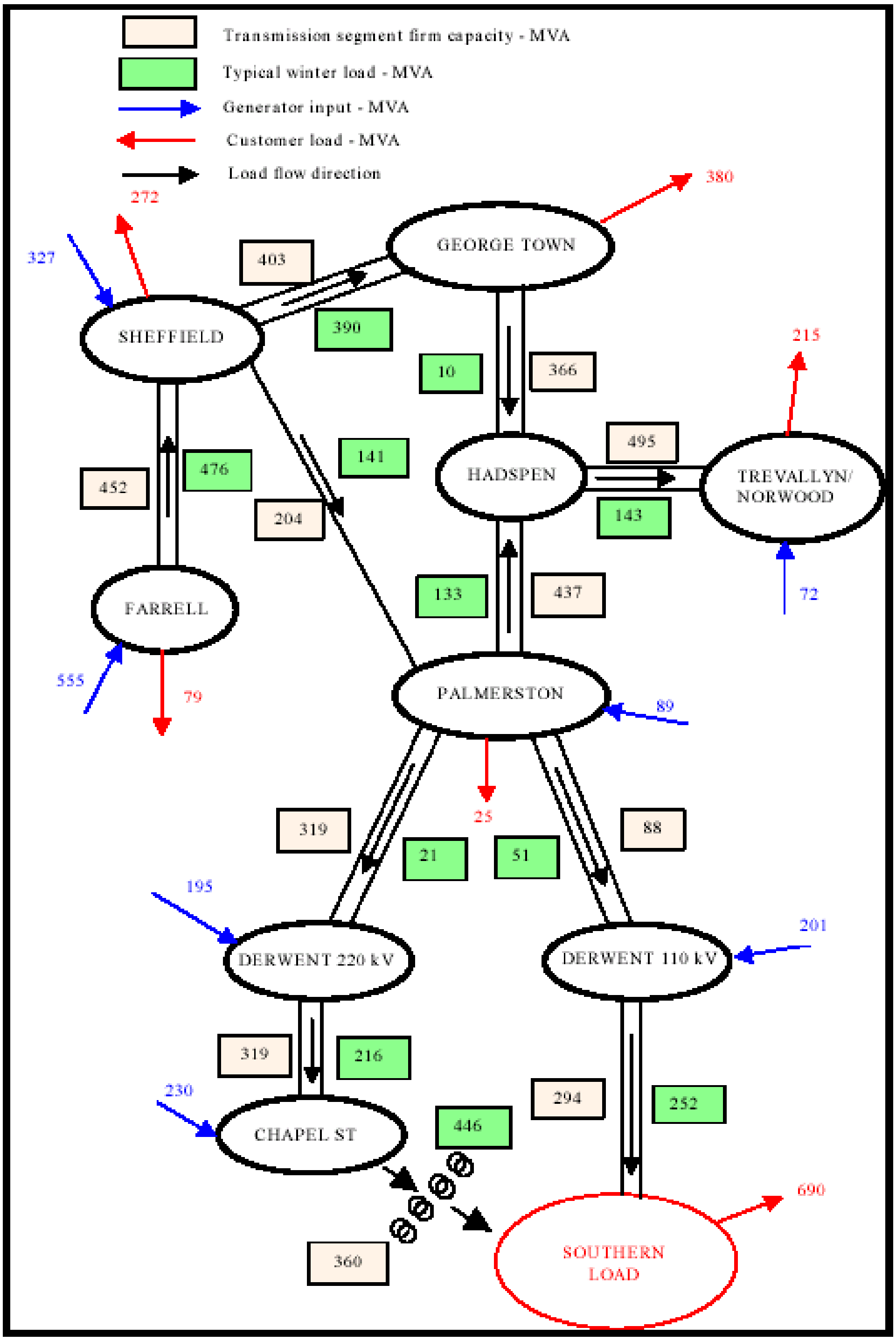
Figure 3.1: Overview of Tasmania's Transmission System

Figure 3.2: Schematic representation of transmission network[12]



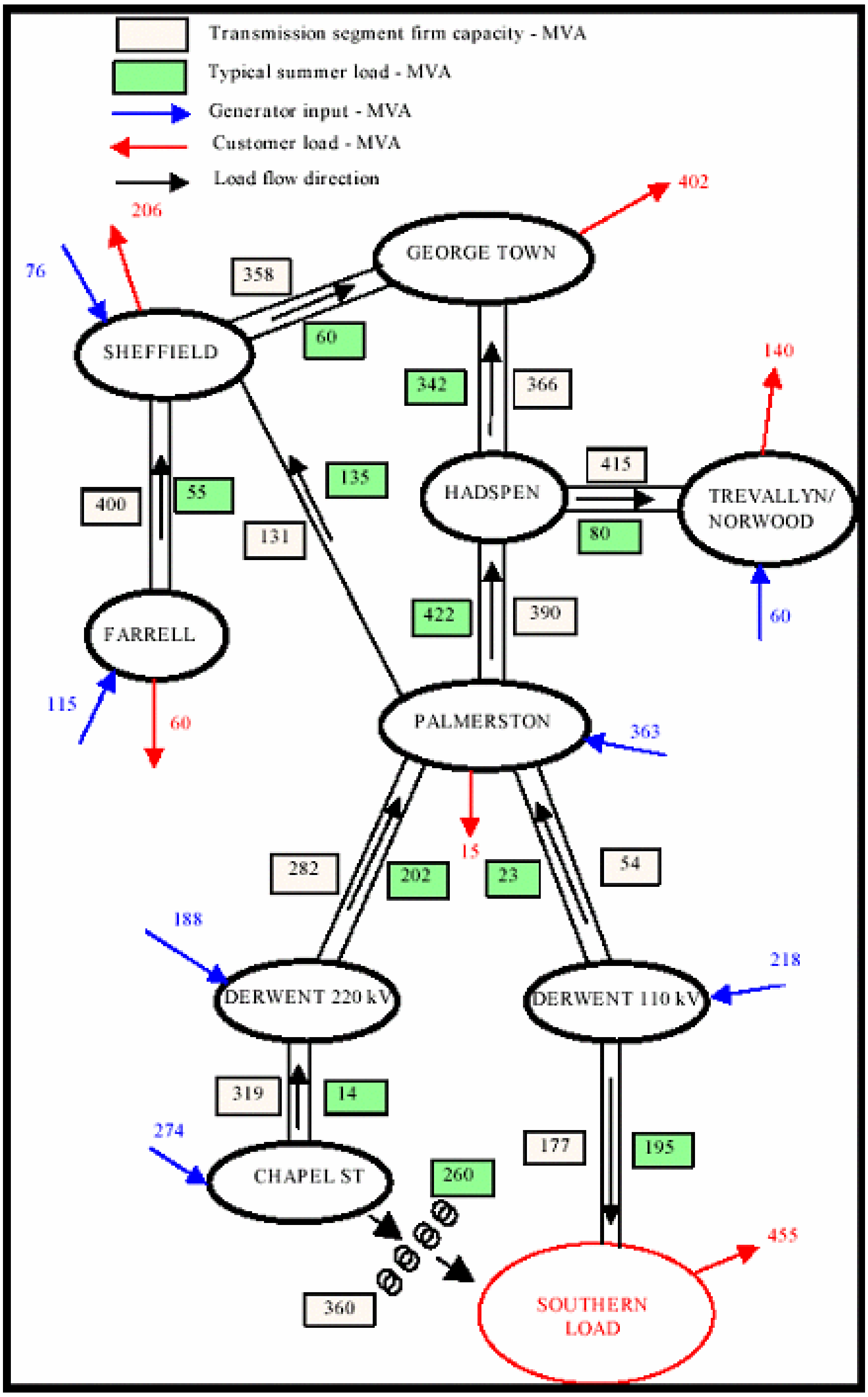
[12] Taken from 2002 Planning Statement.

Figure 3.3: Typical Winter Flows[13]



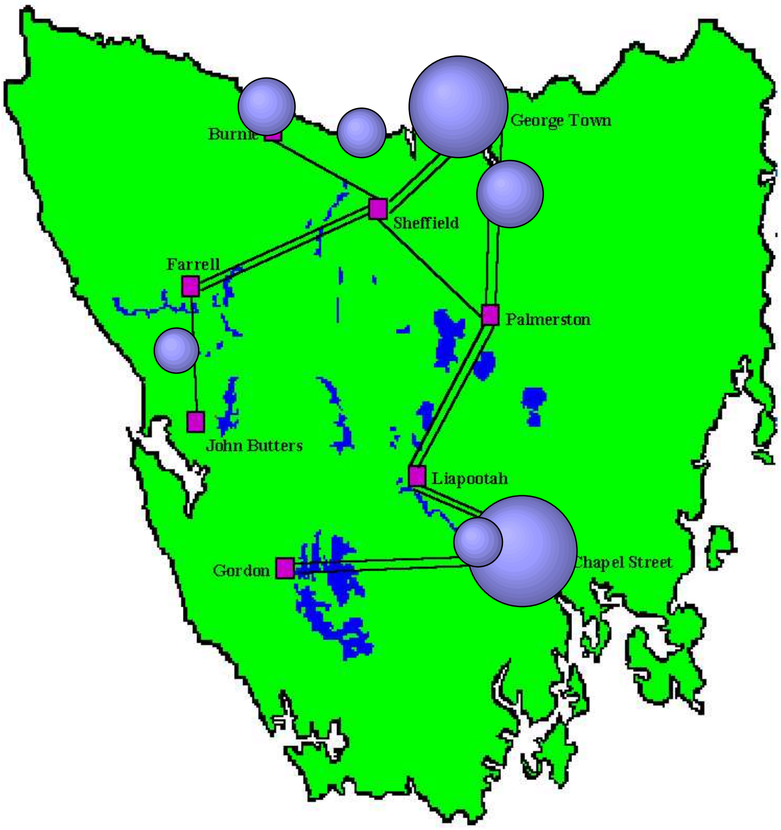
[13] Taken from 2001 Planning Statement

Figure 3.4: Typical Summer Flows



An indication of the local concentration of system load is provided in the following figure 3.5.

Figure 3.5: Tasmanian Load Centres



As part of Transend's licence conditions it is required to report on its performance to the Regulator every year. The key aspects of transmission performance reported are broken into:

- availability;
- reliability;
- quality; and
- and security.

Information on these aspects is gathered from Transend's performance reports, the System Controller's annual reports and Annual Planning Statements.

The reporting agreement between Transend and the Regulator specifies standards for transmission circuit availability, percentage unserved energy and system minutes off supply. The definitions used in Tasmania of these measures is outlined below:

3.2 Availability

Transmission circuit availability is a widely used reliability indicator for transmission businesses. It is the actual circuit hours available for all transmission circuits including overhead lines and underground cables, divided by the total possible circuit hours available. It provides a measure of overall system availability and may be caused by planned outrages (both maintenance and construction) and unplanned outages (both fault and forced). It is also an indicator of the transmission business's asset management practices.

Percentage Unserved energy - is a widely used reliability indicator for transmission businesses. Unserved Energy is the amount of energy that Transend failed to deliver to its transmission customers. The amount of unserved energy (MWh) is normalised by expressing it as a percentage of the energy that would have been served by the network over a defined period (financial year for this report), had the unserved energy events not occurred. It is calculated as follows:

$$\%UnservedEnergy = \left(\frac{Unserved\ Energy(MWh)}{Delivered\ Energy(MWh) + Unserved\ Energy(MWh)} \right) x \left(\frac{100}{1} \right)$$

System Minutes off supply - is the amount of unsupplied energy, expressed in MWh, divided by peak demand, expressed in MW, and multiplied by 60 to convert into system minutes.

$$SystemMinutes = \left(\frac{UnservedEnergy(MWh)}{SystemMaximumDemand(MW)} \right) x \left(\frac{60}{1} \right)$$

It is a measure of the service level of the transmission network in supplying energy to the customers of the network. It includes energy not supplied to customers, during the period of supply interruption, as a result of forced outages and unplanned outages caused by faults. This indicator provides an overall measure of transmission system reliability, capturing the combined effectiveness of network planning, design, operation and maintenance.

The agreed standards (or baseline figures), together with Transend's performance for the year to 30 June 2002 and a comparison with the previous years, are as follows:

Table 3.1: Transmission system reliability Performance targets and results

Measure	98-99	99-00	Performance 00-01	Performance 01-02	Target for 2001-02
Transmission line circuit availability	99.13	99.17	98.96	99.17	98.80
Percentage Unserved energy	0.0042%	0.0068%	0.0142%	0.0025%	<0.0055%
System minutes off supply	15.30	24.91	51.48	9.11	<20

Some trend analysis and benchmarking of key reliability indicators for Transend has been undertaken. The graphs below show trends on a financial year basis in transmission line circuit availability and system minutes off supply.

Figure 3.6: Circuit availability

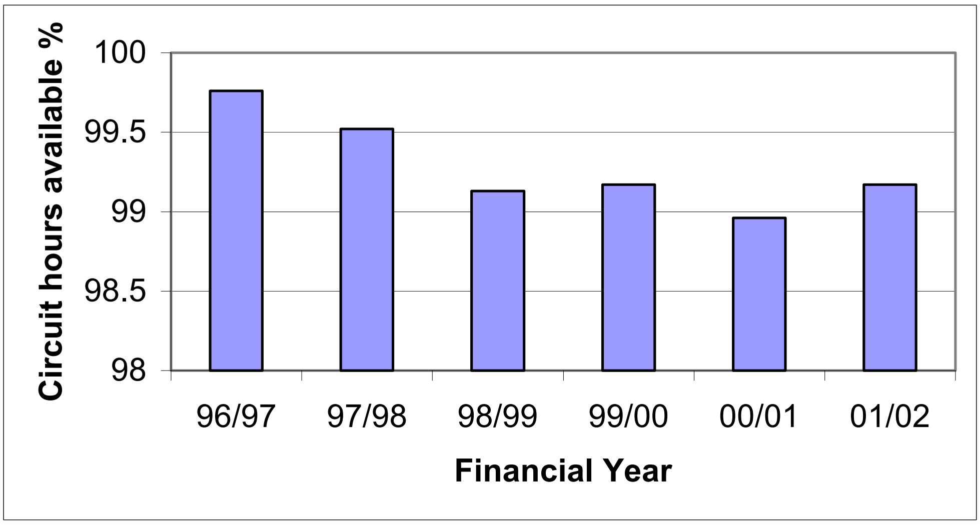
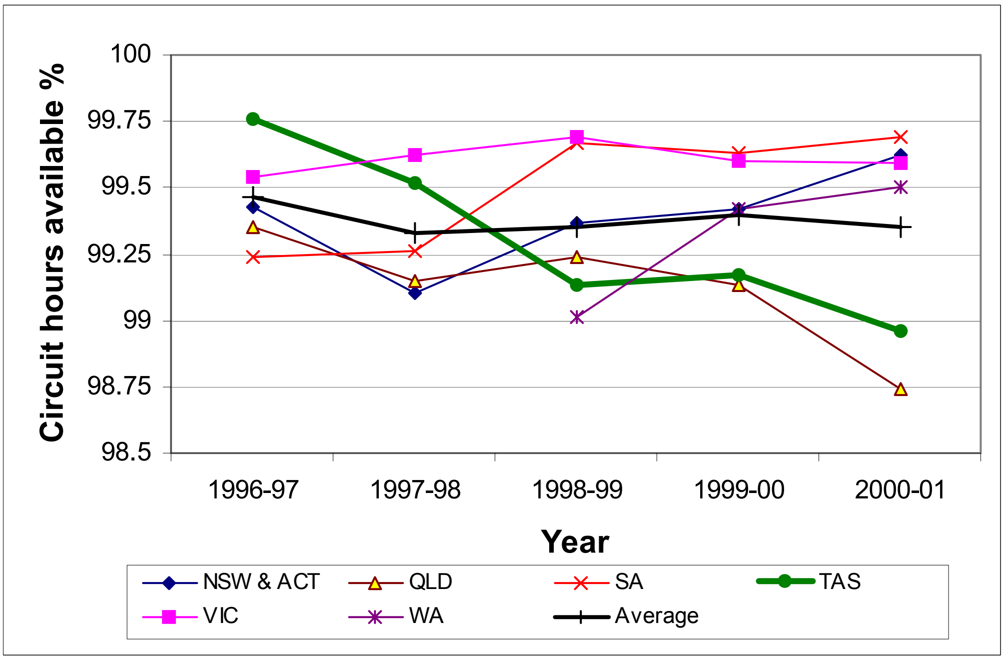


Figure 3.7: Circuit Availability – comparison with other states for 1996 to 2001



Transend's level of circuit availability for 1996-97 and 1997-98 is above that of the Australian average level of availability as reported by the ESAA for 1997-98. However, since 1998-99, Transend's availability is lower than the ESAA average. According to Transend, this reflects the recent increased level of equipment upgrading and replacement impacting on circuit availability, over and above normal maintenance carried out by Transend on its network.

A recent report by Sinclair Knight Merz for the ACCC recommended an availability level of between 99.0 and 99.2 per cent as appropriate for the NSW electricity transmission company TransGrid.

While Transend's performance on circuit availability has been declining in recent years and is close to the bottom when compared to other states as given in figure 3.7, it is encouraging to see that the decline in performance is now being arrested, as shown in figure 3.6.

Figure 3.8: Transend Networks – System Minutes off supply

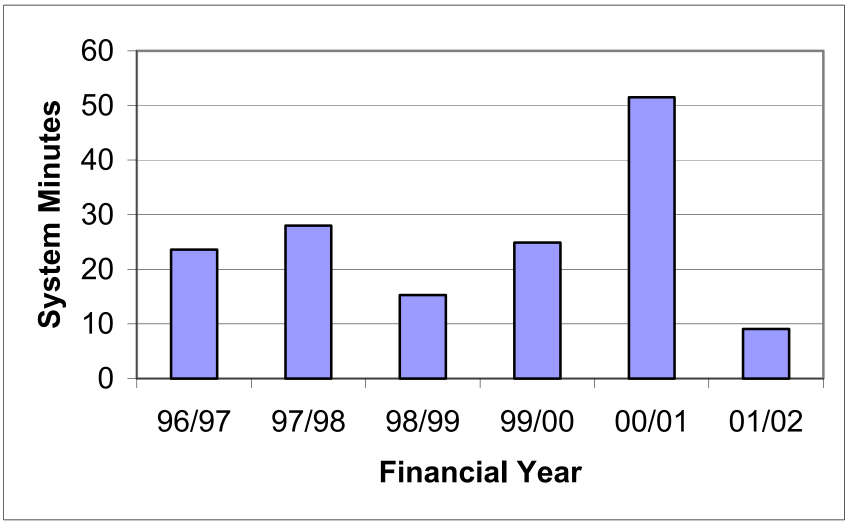
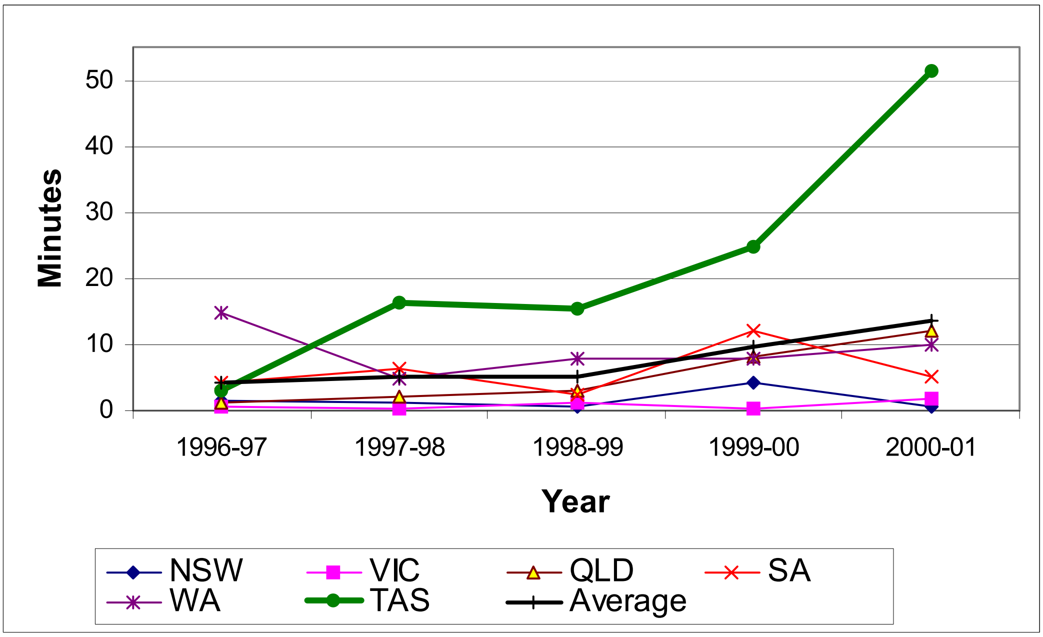


Figure 3.9: System Minutes off supply – comparison with other states for 1996 to 2001



Source: ESAA, Electricity Australia 2002.

The annual trend of system minutes off supply fluctuates significantly from one year to the next. Reliability performance in terms of system minutes of unsupplied energy can be adversely affected by single significant incidents, particularly on weakly "meshed" parts of the network. For example, in 1996-97 a single severe storm caused an outage in a weakly "meshed" part of the network resulting in 17.27 system minutes. In 1998-99, an outage on a radial line caused by a tractor toppling a lattice tower, reduced performance by 9.4 system minutes and in 2000-01, 45.80 system minutes were lost as a result of a series of incidents that occurred at Risdon Substation.

The Tasmanian customer base is heavily concentrated, with some two-thirds of the energy supplied to only five large industrial customers. Events involving any one of these supply points have a significant impact on the system minutes off supply performance measure.

Transend level of system minutes off supply is consistently higher than the other Australian transmission businesses as shown in figure 3.9 and as outlined previously. This is due in part to the weaker “meshing” of Transend’s network making it susceptible to single significant incidents. However, as shown in figure 3.8, Transend recorded a vastly improved performance in 2001-02 bringing its performance into line with interstate entities.

3.2.1 Component availability

The availability of transmission components is measured in terms of the time for which the components are available, divided by the product of the total time and the number of transmission circuits being considered.

Table 3.2: Transmission component availability (%)

Year	1998-1999	1999-2000	2000-2001	2001-2002
Transmission line circuit	99.13	99.17	98.96	99.17
Transformer circuits	98.47	98.70	99.17	99.13
Capacitor banks	99.93	99.61	99.92	98.83

Transmission line availability has improved from last year to be comparable to previous years, and transformer availability has improved on previous years’ performance. On the other hand, there has been a significant decrease in the availability of capacitor banks.

3.2.2 Fault Levels

Substations whose prospective fault levels are predicted to exceed 80 per cent of the rated breaking capacity are indicated in table 3.3. According to the System Controller, planned system augmentations are not expected to have a significant effect on substation fault levels.

Table 3.3: Substation circuit breaker capability as a percentage of fault level[14]

Circuit breaker location	Predicted (2002)
Burnie 22 kV	88%
Creek Rd 110 kV	92%
Devonport 22 kV	85%
Railton 22 kV	108%
Smithton	81%

3.3 Reliability

Table 3.4: Connection Point Reliability Due To Forced Outages 2001-02

Type of Connection	Firm or Non-Firm	Number of connection points	Target % unserved energy	% unserved energy	Target number of forced outages	Average Number of forced outages p.a.	Target duration of forced outage (min)	Average duration of forced outage (min)
Distribution	Firm	29	0.0050	0.0028	0.20	0.38	10	95
	Non-firm	21	0.0200	0.0057	0.50	1.19	25	63
Direct Connection	Firm	10	-	0.0009	-	0.50	-	35
	Non-firm	8	-	0.1076	-	0.75	-	49
Generation	Firm	19	-	-	0.10	0.00	5	0
	Non-firm	23	-	-	0.50	0.26	90	5

Note: shading indicates where targets have not been met.

The number and duration of forced outages for distribution connection points was above the target set by Transend. The results for firm connection points were predominantly affected by one long outage at Sorell of almost 37 hours' duration. Excluding this outage reduces the average duration to less than 19 minutes, which is closer to the target of 10 minutes. Transend has set the target for the number of forced outages affecting firm distribution connection points as six per annum or 0.2 on average per connection point. In 2001-02, there were eleven forced outages and this does not include the loss of supply from Trevallyn, which was not counted as an outage since the entire substation was not affected. Further, Trevallyn is treated as a single connection point for reporting purposes.

[14] Extracted from 2002 Planning Statement.

Table 3.5: Connection Point Reliability Due To Planned Outages 2001-02

Type of Connection	Firm or Non-Firm	Number of connection points	Target % Unserved energy	% Unserved energy[15]	Target Number of planned outages p.a.	Average Number of planned outages p.a.	Target duration of planned outage (min)	Average duration of planned outage (min)
Distribution	Firm	29			0.20	0[16]	20	0
	Non-firm	21			0.70	0.38	350	2509
Direct Connection	Firm	10	-		-	0.40	-	155.3
	Non-firm	8	-		-	0.13	-	36.4
Generation	Firm	19	-	-	0.10	0.11	15	306
	Non-firm	23	-	-	0.50	0.48	480	292

Note: shading indicates where targets have not been met.

The number and duration of planned outages for distribution connection points was above the target set by Transend. The results for firm connection points were predominantly affected by four outages at Electrona amounting to almost 32 days duration. Two outages due to repair work on Meadowbank and Tarraleah substations led to 5 days outage for the Meadowbank connection point. Removing these outages brings the average outage down to less than 22 minutes. There were three outages to one of Comalco’s firm connection points lasting 22 hours. This accounted for the bulk of the planned outages for direct connect connection points. Generation outage durations exceeded the target due to the repair work on Meadowbank and Tarraleah substations.

3.3.1 Connection point security for firm connection points

The following table shows instances when a firm connection point became non-firm due to system configuration during planned and emergency outages only. It does not include instances where the connection point becomes “non-firm” due to connection point loading exceeding the “firm” rating with all equipment in service.

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[15] Transend does not report unserved energy for a planned outage. This does not mean that end customers are not affected. In a number of cases end customers experienced lengthy supply outages as a result of Transend planned works.

[16] The lack of planned outages does not imply that no maintenance was undertaken. Maintenance at a firm connection point can often be undertaken without causing an outage.

Table 3.6: Number and duration of times when firm connection point become non-firm 2001-02

	Average Number Of Times Non-Firm		Target	Average Total Duration Non-Firm (Min)		Target (min)
	2001-02	2000-01		2001-02	2000-01	
Distribution	7.59	5.68	2	17 150	12 092	1200
Direct Connection	7.60	2.60	-	16 326	4 513	-
Generation	1.00	1.00	-	6 839	6 970	-

Note: shading indicates where targets have not been met.

Only three of the 29 firm distribution connection points were firm for the entire reporting period and only 9 were non-firm for less than the target value of 1200 minutes or 20 hours. Four connection points, namely Ulverstone, Emu Bay and both George Town buses were non-firm for over 47 days during the financial year. Ulverstone and Emu Bay were non-firm due to work on the 110 kV Sheffield-Burnie number 2 transmission circuit. The George Town buses were non-firm due to replacement of a transformer at the George Town substation.

Of the ten firm direct connect connection points, all were non-firm for at least ten hours. Four connection points, namely Boyer D&E bus, Risdon A&B bus, Boyer F&G bus and Emu Bay were non-firm for more than a week. The Boyer buses were non-firm due to refurbishment of the Boyer substation and the Risdon connection point was non-firm due to substation redevelopment. Emu Bay was non-firm for the same reason as for the distribution connection point mentioned above.

Security deteriorated from 2000-01 for all connection types other than generation where security is essentially identical to the preceding year. Security at direct connect connection points has deteriorated threefold, mostly due to substantial substation refurbishment work.

3.4 Quality

The major issues faced by the end customer with regards to the quality of electricity supply are associated with frequency and voltage excursions beyond the acceptable thresholds.

A total of 8 330 frequency deviations were observed outside the normal frequency band, of which 28 were outside 1 Hz deviation from 50 Hz. More details are given in, the Regulator's ESI Performance Report (refer to section 5.2.2 of that Report).

3.4.1 Voltage

During the period 1 July 2001 to 30 June 2002, voltage levels on the 220 kV and 110 kV buses were maintained within the required voltage range of +/-10 per cent of nominal voltage, apart from short fluctuations caused by events on the power system outside the control of the System Controller.

The System Controller manages the voltage levels on a number of buses within ranges specified in contracts (Connection Agreements). These levels were maintained within the identified range except those listed in figure 3.7. No adverse effects of these deviations have been reported to the System Controller. Bus voltage fluctuations at 11 kV and 110 kV levels during the year caused by customer load variations are not included in the report.

Table 3.7: Voltage excursions outside Code or contract ranges

Bus	Date	Period (min)	Comment
Risdon 11kV	10 November 2001	7	New substation commissioning
Devonport 110kV	12 November 2001	10	Incident at Devonport
North Hobart 22kV	10 December 2001	14	Loss of 110kV Creek Road–North Hobart transmission line
Risdon 11kV	31 December 2001 – 1 January 2002	350	New substation commissioning
Queenstown 11kV	26 January 2002	9	Loss of 110/11kV transformer at Queenstown
Bridgewater 110kV	19 February 2002	14	New substation commissioning
Emu Bay 33kV	15 April 2002	9	Loss of 110kV Paloona–Ulverstone transmission line

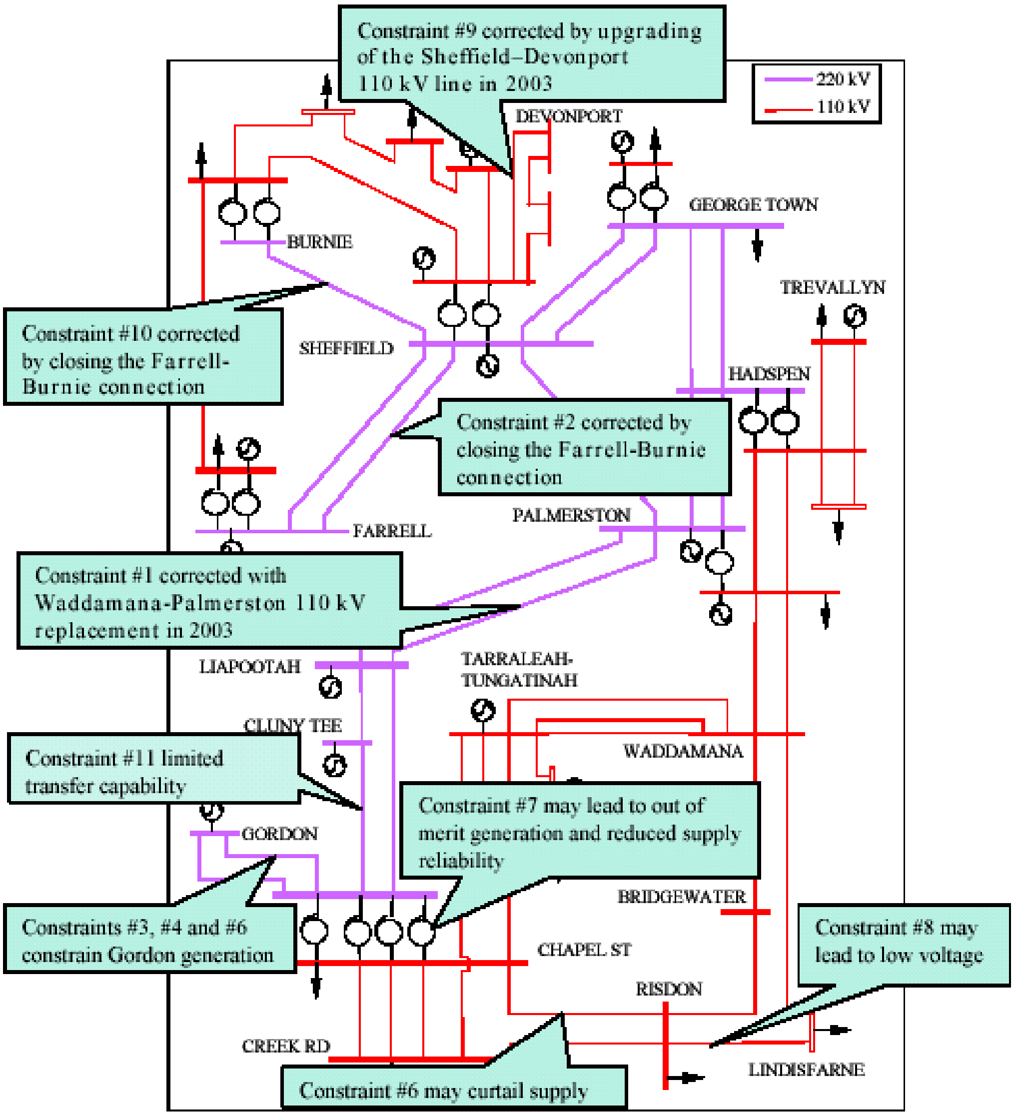
3.5 Constraints

There are a number of constraints on the transmission system, some of which may affect performance. To illustrate the relative importance and potential impact of these constraints, details are provided below.

3.5.1 Transmission network constraints

There are a number of constraints on the transmission network. They impact the system in a number of ways; from restricting generation from some stations to restricting supply under some contingencies.

Figure 3.10: Transmission system constraints[17]



[17] Extracted from 2002 Planning Statement.

Liapootah–Palmerston 220 kV No. 2 circuit	
Constraint #1	An outage of the Liapootah–Palmerston 220 kV No. 2 circuit (circuit with a higher thermal rating) during northern generation and peak load conditions (summer or winter) will overload the Tungatinah–Lake Echo–Waddamana and Waddamana–Palmerston 110 kV circuits by about 80%.
Impact	Potential constraint on generation north of Palmerston. Not serious if generation can be rescheduled. Possible spill during winter. The remaining No. 1 Liapootah–Palmerston transmission line will be constrained to the thermal limit of the Palmerston–Waddamana 110 kV lines after the loss of the above circuit. When No. 2 Palmerston–Liapootah 220 kV line is out of service, power can only be transferred from north to south through the remaining 220 kV transmission line (No. 1) and the 110 kV transmission lines from Palmerston to Waddamana. Although the thermal rating of No. 1 Palmerston–Liapootah 220 kV line is 304 MVA under winter conditions, it cannot be loaded to that level under these circumstances since the loss of this line (now the critical credible contingency) would transfer the full north–south power flow to the Palmerston–Waddamana 110 kV lines and severely overload them. Therefore, when generation is rescheduled subsequent to an outage of No. 2 Palmerston–Liapootah 220 kV circuit, the loading of No. 1 Palmerston–Liapootah 220 kV line is constrained to the thermal ratings of the Palmerston–Waddamana 110 kV circuits under winter conditions.
Remarks	Proposed Waddamana–Palmerston 110 kV circuit upgrade (in 2003) will relieve the overloading of that circuit.
Farrell–Sheffield 220 kV circuit	
Constraint #2	An outage of one Farrell–Sheffield 220 kV circuit will overload the remaining circuit by approximately 10% when the west coast generators are operating at full capacity to supply the winter peak load, and by about 30% when they are operating at full capacity to supply the summer peak load. Following the permanent loss of one of the circuits, loading on the transmission line has to be reduced to 180 MW to ensure system frequency can be maintained within the single credible contingency band following the loss of the single circuit.
Impact	Potential constraint on west coast generation may lead to spill.
Remarks	This overloading can be avoided by closing the Farrell–Burnie 110 kV connection. Closing this tie when all the transmission lines between Burnie and Sheffield are in service satisfies this requirement. This practice will significantly remove constraints to the west coast generation for the present installed capacity.

Gordon–Chapel Street 220 kV circuit	
Constraint #3	An outage of one Gordon–Chapel Street 220 kV circuit will overload the other circuit when all three Gordon machines are generating at full capacity.
Impact	Will constrain the Gordon generation and may lead to out-of-merit generation in extreme circumstances.
Remarks	The power transfer on the remaining 220 kV line could be limited in order to comply with frequency management requirements and could be as low as 144 MW.
Gordon–Chapel Street 220 kV circuit	
Constraint #4	Gordon–Chapel Street 220 kV transmission is constrained during high ambient temperatures with no wind.
Impact	Will constrain Gordon generation and may lead to out-of-merit generation in extreme circumstances.
Remarks	Constrained by about 20 MVA compared with the normal summer conditions (at 25^0C and 0.5 m/s).
Gordon–Chapel Street 220 kV circuit	
Constraint #5	Gordon–Chapel Street 220 kV transmission needs to conduct energy at times of snow to reduce snow loading on the conductors.
Impact	Requires Gordon generation which may be out-of-merit during winter periods when preferred generation is from run-of-river and small storage hydro generators.
110 kV circuit to Risdon Substation	
Constraint #6	An outage of one 110 kV circuit to Risdon Substation from either Chapel Street or Creek Road will overload the other circuit by about 25% of circuit rating during peak load conditions in summer or winter.
Impact	Potential supply curtailment and reduced reliability of supply.
Remarks	Supply to Risdon becomes non-firm by about 75 MVA at peak periods. To be addressed as part of an upgrade of southern transmission.
Chapel Street auto-transformers	
Constraint #7	An outage of one Chapel Street auto-transformer under winter maximum load conditions will overload the remaining Chapel Street auto-transformers (other than the transformer T1 which is rated at 200 MVA) by as much as 25%.
Impact	Potential out-of-merit 110 kV circuit-connected generation or reduced reliability of supply to southern load. Low risk with high impact for extended outages.

Risdon–Lindisfarne 110 kV circuit	
Constraint #8	An outage of the Risdon–Lindisfarne 110 kV circuit during periods of peak demand will cause low voltage at the Lindisfarne 110 kV bus.
Impact	Close to violating the TEC requirements under winter peak load conditions.
Remarks	Proposed additions of capacitor banks at Rokeby and Sorell substations will relieve the problem.
Sheffield–Devonport 110 kV circuit	
Constraint #9	An outage of Sheffield–Devonport 110 kV line during winter peak load conditions will overload the Sheffield–Wesley Vale 110 kV line by about 10% and cause low voltage in the Devonport–Wesley Vale area.
Impact	Potential supply curtailment and reduced reliability and/or quality of supply.
Remarks	Upgrading the Sheffield–Devonport 110 kV line will relieve the overloading, and the proposed addition of two 5 MVAr capacitor banks at Devonport will improve the voltage profile in the area.
Sheffield–Burnie 220 kV circuit	
Constraint #10	An outage of Sheffield–Burnie 220 kV circuit during winter peak load conditions will overload the Sheffield–Burnie 110 kV circuit by about 10% and Paloona–Ulverstone 110 kV circuit by about 30%. The voltages around Burnie drop below 0.9 pu.
Impact	Potential supply curtailment and reduced reliability and/or quality of supply.
Remarks	If the normally open Farrell–Burnie 110 kV connection is closed, this overloading can be avoided. The proposed additions of capacitor banks at Burnie 110 kV bus (2003), the Sheffield 110 kV bus (2004), and Smithton and Port Latta 22 kV buses will relieve the under-voltage problem in the area.
Liapootah–Chapel Street 220 kV circuits	
Constraint #11	The Liapootah–Chapel Street corridor is limited to about 300 MVA.
Impact	At high southern loads may require out-of-merit operation of Gordon power station.
Remarks	This limitation is subject to plans for the reinforcement of supply to the southern load.

In the present system, an outage of the Liapootah–Palmerston 220 kV No. 2 circuit during northern generation and peak load conditions (summer or winter), results in overloading of the Tungatinah–Lake Echo– Waddamana and Waddamana–Palmerston 110 kV circuits by up to 80 per cent. An upgrade of the Waddamana–Palmerston 110 kV circuit is planned for completion by November 2003 to substantially alleviate this constraint.

3.5.2 Transmission system access constraints

Transend has reported that on a number of occasions access to plant for maintenance or system improvement has been denied or severely restricted by the requirements of the Code. Parallel circuits or plants having insufficient or no redundancy generally cause these restrictions. These access constraints can delay maintenance by months. Transend are looking for ways to reduce these constraints and one such opportunity is the redevelopment of the southern 220 kV system. The most significant and recently encountered access constraints and their impacts are given in Table 6.6 of the Annual Planning Statement, 2002.

3.5.3 Terminal substation capacity constraints

The loadings on each terminal substation on the transmission system and the effect of load growth for the next ten years are projected each year. From the latest figures, it is evident that a number of substations are working at or above their firm capabilities, giving rise to reliability issues in those areas, eg activating automatic load shedding schemes and radialising substation transformers. Substations which either presently or are forecast to exceed their firm capacity in the next 10 years are listed in Table 3.8 below.

Table 3.8: Terminal substation firm capacity and load forecast

Terminal Substation	Emergency N-1 (4hr Rating) MVA		Aurora 2001 Load Forecast (with Gas)			Aurora 2001 Load Forecast (with Gas)			Aurora 2001 Load Forecast (with Gas)		
			2001/2002			2005/2006			2010/2011		
	Trans-former	Equip-ment	MVA	Trans-former %	Equip-ment %	MVA	Trans-former %	Equip-ment %	MVA	Trans-former %	Equip-ment %
Lindisfarne	54	34	49.6	92	146	46.9	87	138	41.3	76	121
North Hobart	72	60	59.8	83	100	55.4	77	92	62.1	86	104
Norwood	60	54	66.5	111	123	63.6	106	118	66.4	111	123
Palmerston	9	9	10.6	118	118	11.5	128	128	12.6	140	140
Queenstown 22kV	9	9	9.8	109	109	13.3	148	148	15.5	172	172
Queenstown 11kV (CMT)	14	14	18.8	135	135	19.5	139	139	20.4	146	146
Railton	60	60	51.9	86	86	55.4	92	92	60.0	100	100
Smithton	18	15	27.5	153	183	31.0	172	207	35.6	198	238
St Marys	12	12	10.9	91	91	11.7	98	98	12.7	106	106
Trevallyn	120	120	146.9	122	122	132.1	110	110	145.9	122	122
Wesley Vale	30	22	27.2	91	124	28.2	94	128	27.4	91	124

Note: shading indicates load greater than 100 percent.

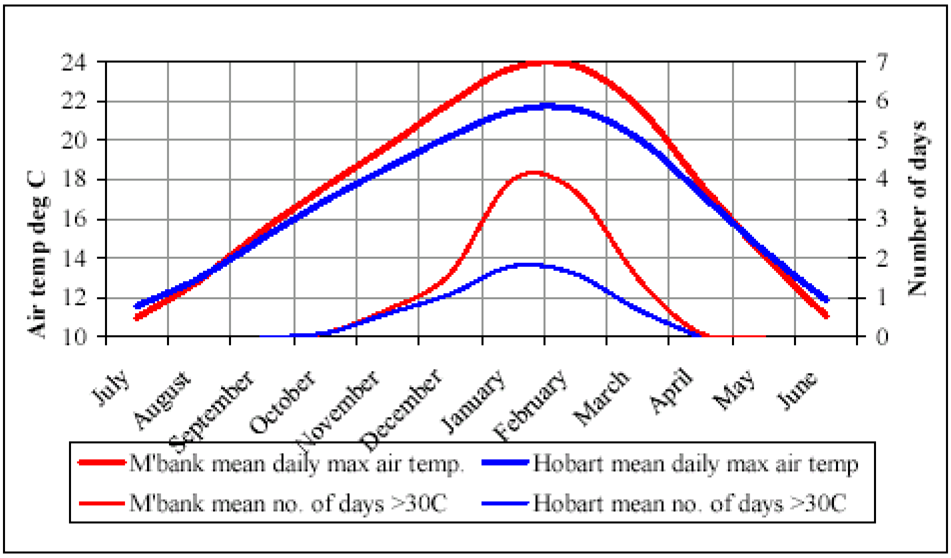
3.6 Conductor current ratings

The key factor determining conductor current ratings is the conductor temperature. Conductor ratings are specified by:

- ambient temperature; and
- steady-state or 15-minute rating.

Temperatures can also vary significantly in locations within Tasmania, as shown in Figure 3.11.

Figure 3.11: Temperature comparison - Meadowbank and Hobart[18]



3.7 Supply area adequacy and substation capability

Supply area adequacy is concerned with the ability of the power system to meet the forecast demand at each terminal substation within specified supply areas.

The Tasmanian power system has been subdivided into four supply areas for consideration of supply area adequacy and substation capability. These are:

- southern area
- northern area
- north-Western area
- west coast area

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[18] Extracted from 2002 Planning Statement.

Southern area

Supply to southern loads is from Gordon power station, via the 220 kV transmission from Liapootah and via the 110 kV transmission from Tungatinah and Waddamana.

Several factors affect the firm supply to southern loads:

- ambient temperature
- southern load level
- availability of auto transformers at Chapel Street
- availability of Gordon power station

The planned Southern power system project, which provides a 220 kV supply point at Lindisfarne, is expected to provide an alternative to these constraints.

Northern area

The northern area is fed via three major 220 kV substations: Palmerston, George Town, and Hadspen and is supported locally by three power stations, Poatina, Trevallyn and Bell Bay. A 110 kV network provides support to the 220 kV circuits between Palmerston and Hadspen, with additional 110 kV circuits feeding load at Trevallyn, Norwood, Avoca and St Marys.

George Town Substation is one of the most heavily loaded in the State. It supplies two major and three smaller industrial customers, as well as retail load at 22 kV.

Trevallyn and Norwood are both operating beyond their firm capacities during peak winter periods. This will be corrected with the establishment of an additional substation at Mowbray. The Avoca and St Marys substations are non-firm sources of supply because a single transmission line supplies them.

North-western area

Sheffield Substation is the major supply point for the north-western area.

Hydro Tasmania has committed to the installation of a further 54.25 MW of wind generation in the Woolnorth area.

An interim transmission upgrade is planned and entails stringing a second Port Latta–Smithton110 kV line and provision of 35 MVA firm transformer capacity at Smithton Substation. In the longer term the transmission network will require a more significant upgrade as wind energy generators in the area develop.

West coast area

West coast area loads are supplied from Farrell Substation. The loads in this area are relatively small and are not expected to vary significantly over the next 15 years.

3.8 Loss Factors

The overall system is subject to losses that appear to be fairly constant in total, as shown in transmission and distribution losses but which are reducing as a percentage of energy generated (as shown in Figure 3.12). Both figures show both transmission and distribution losses.

Figure 3.12: Total annual average system losses (generation minus sales)

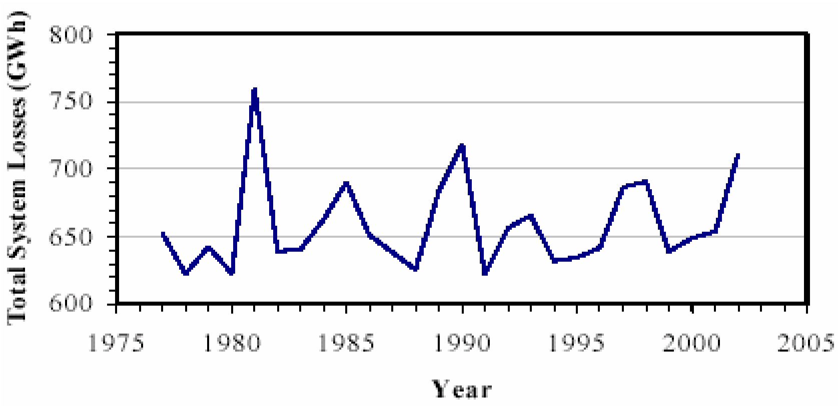
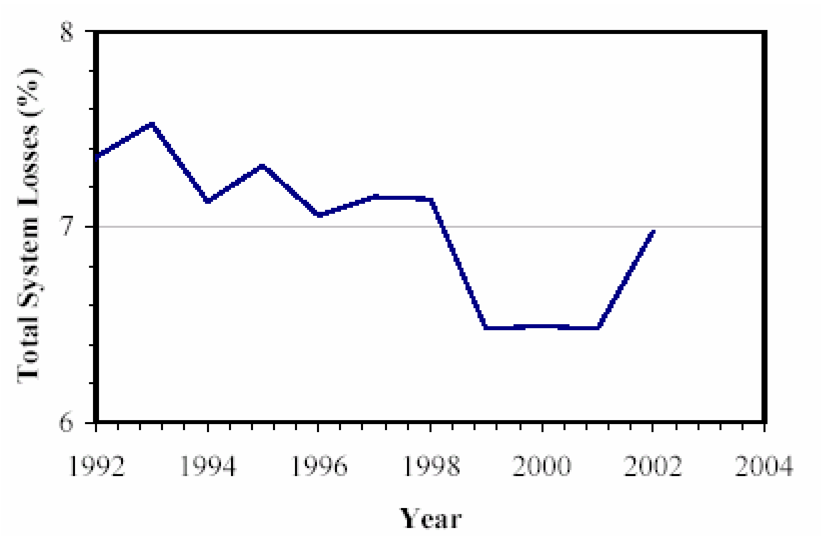


Figure 3.13: Total annual average system losses (as a percentage of generation)



3.9 Transmission system augmentation

A series of network improvement projects are carried out to improve the safety, reliability and capacity of the transmission system. The project work includes:

- elimination of substandard clearances;
- replacement of transformers;
- replacement of circuit breakers with SF6 units;
- replacement of voltage transformers with SF6 units;

- protection and control improvements;
- replacement of non-compliant current transformers; and
- replacement of non-compliant disconnectors.

3.9.1 Projects in progress

The following network improvement projects are in progress at the moment:

- development of Risdon Substation
- Smithton Substation development

3.9.2 Future projects

Committed and advanced network improvement projects are listed below:

- Waddamana circuit breaker rationalisation
- George Town Substation new transformer
- Queenstown transformer replacement
- Waddamana-Palmerston 110 kV replacement
- Upgrading Liapootah-Palmerston 220 kV line
- Port Latta–Smithton 110 kV second circuit
- Transmission line upgrade projects
- Sheffield - Wesley Vale
- Sheffield - Devonport
- Devonport - Wesley Vale
- Waddamana - Bridgewater
- Meadowbank - New Norfolk
- Tarraleah - Meadowbank
- Advanced Projects
- New Tarraleah-Liapootah 220 kV connection
- Southern transmission (220 kV supply point to Lindisfarne from Liapootah and Tarraleah area)
- Mowbray Substation
- Sheffield Substation

- Upgrading of Norwood to Scottsdale and Derby lines

3.9.3 Capacitor installations

Location and details of the proposed capacitor installations are listed in Table 3.9 below.

Table 3.9: Proposed capacitor installations[19]

Location	kV	Size MVAr	Proposed year of installation
Smithton	22	2 x 5	2004
Port Latta	22	2 x 5	2004
Scottsdale	22	2 x 5	2004
Trevallyn	22	3 x 5	2004
Devonport	22	2 x 5	2004–05
Hadspen	110	1 x 30	2004–05
Kingston	11	2 x 5	2004–05
New Norfolk	110	1 x 30	2004–05
Norwood	22	2 x 5	2004–05
Sorell	22	2 x 5	2004–05
Sheffield	110	1 x 30	2005–06
Knights Road	11	1 x 5	2006–07
Rokeby	11	2 x 5	2006–07

3.10 Impacts of Basslink

The following three figures indicate the impact of Basslink on the transmission system for winter peak periods at five-year intervals, in 2005–06, 2010–11 and 2016–17:

Figure 3.14 shows the transmission system with Basslink importing 480 MW into Tasmania.

Figure 3.15 shows no import or export.

Figure 3.16 shows the transmission system dealing with the largest possible export of 630 MW.

According to the System Controller, in all cases, with all transmission elements in service and all capacitor banks available, all voltages can be maintained within the prescribed limits. Transmission elements supplying southern load are shown as being stressed in all cases. These limitations would be addressed through the proposed southern system security project transmission.

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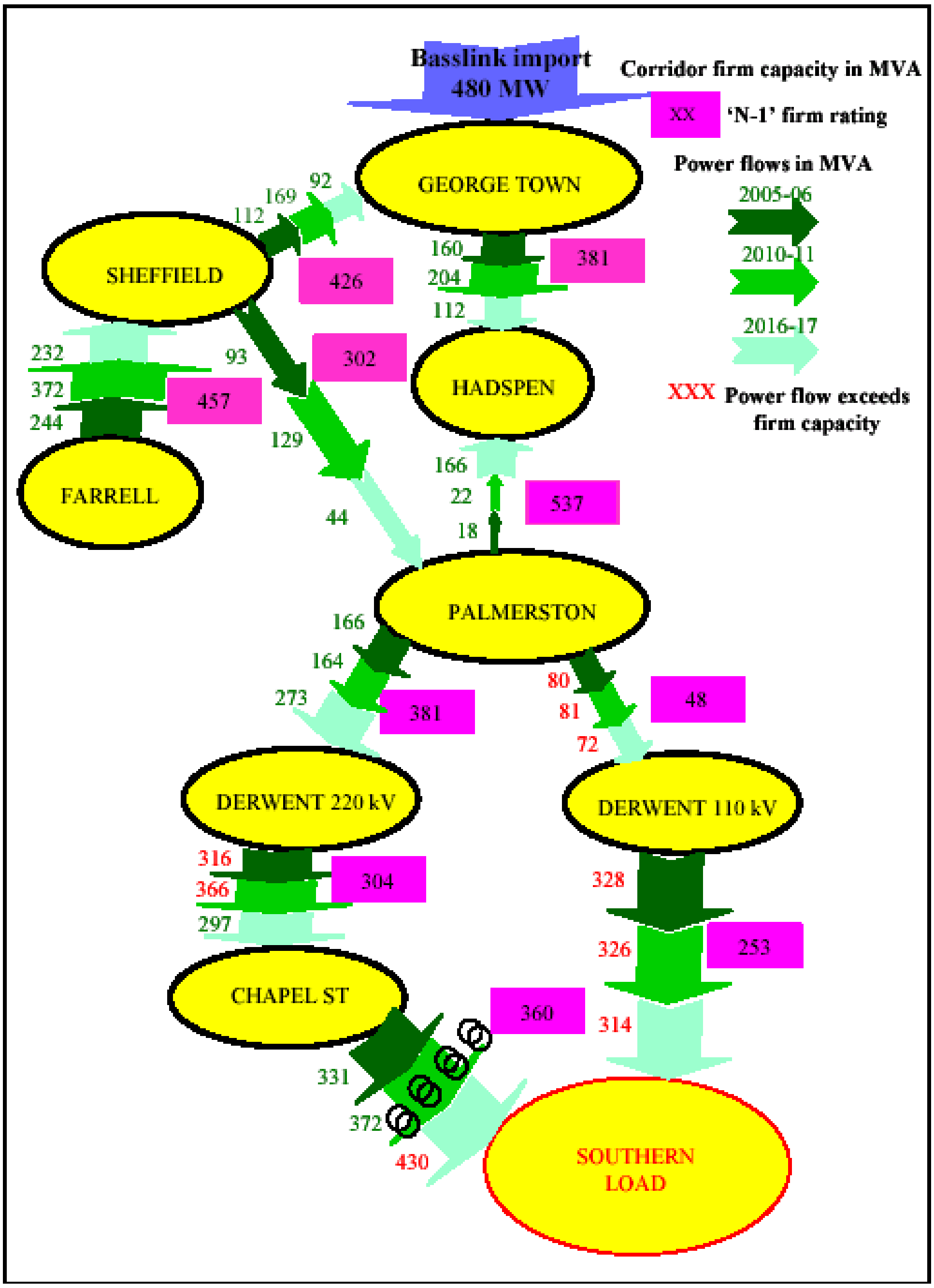
[19] Extracted from 2002 Planning Statement.

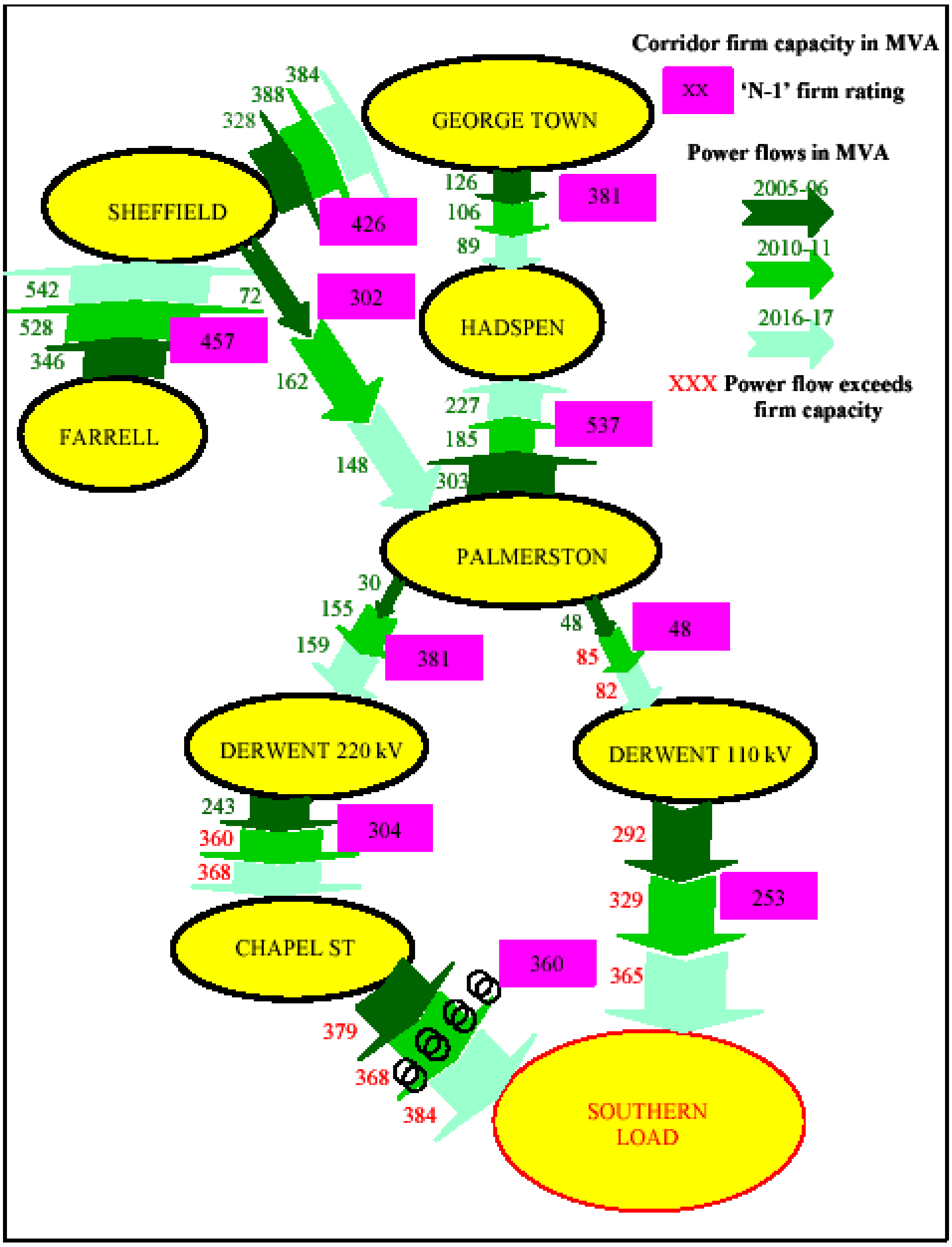
Figure 3.14: Peak winter flows with Basslink importing 480 MW[20]



The effect of the larger than normally intended import is to cause northern generation to be reduced. Supply to the south would remain virtually unaffected with the usual transmission limitations still in place.

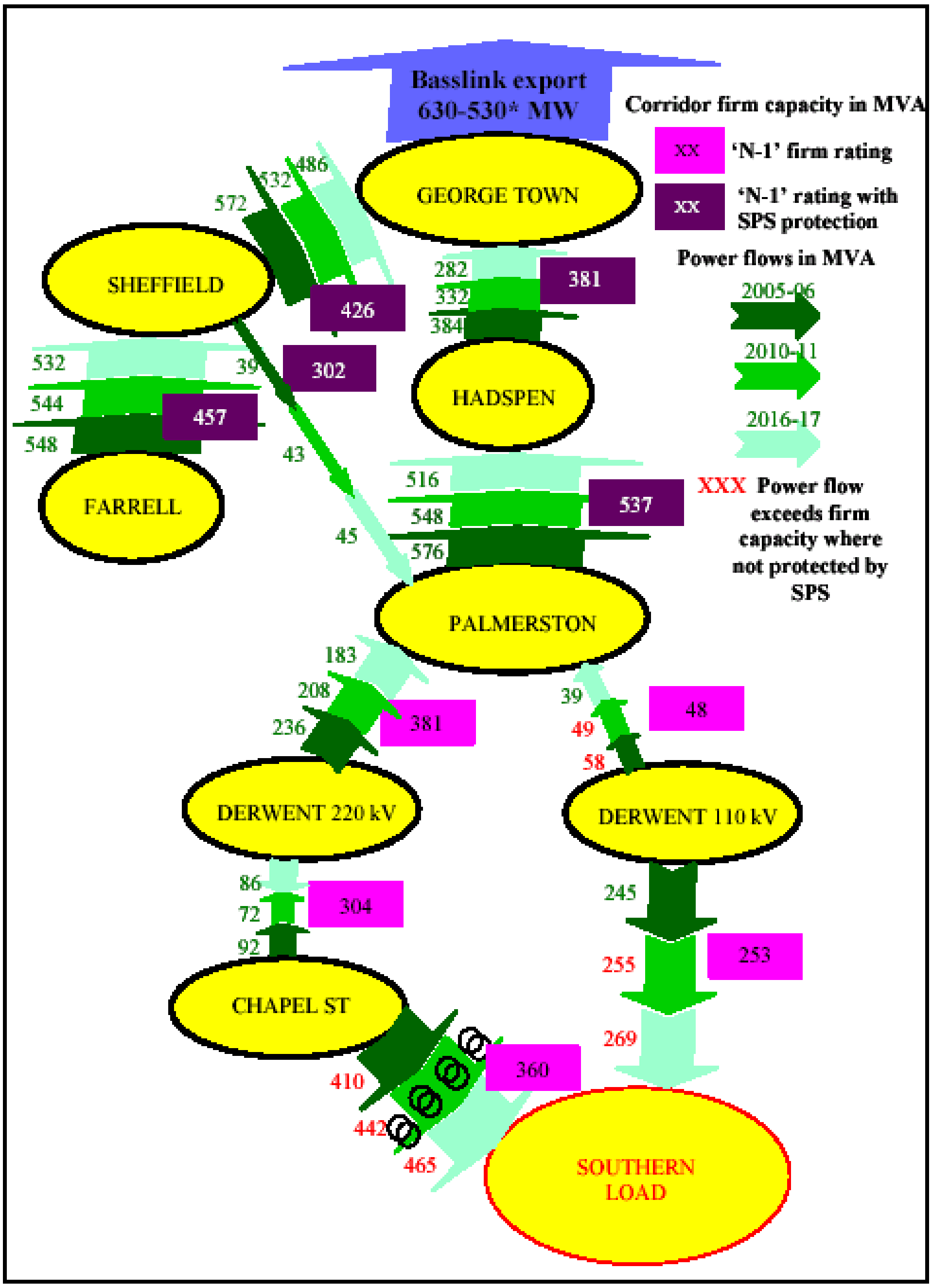
[20] Extracted from 2002 Planning Statement.

Figure 3.15: Peak winter flows with Basslink neither importing nor exporting



With no export or import, the transmission system operates in the normal peak winter load mode with maximum run-of-river and small storage generation.

Figure 3.16: Peak winter flows with Basslink exporting 630 MW (530 MW 2016-17)



*In 2016-17 the export is limited to 530 MW because of lack of sufficient generation. Note, only committed generation proposals have been included in these studies.

3.11 Impacts of new generation

Four large wind farms have been proposed:

Woolnorth (Hydro Tasmania) with a combined total of 138 MW made up in three stages:

- 10.5 MW completed in 2002;
- 54.25 MW committed, with expected completion in 2003; and
- 73.5 to 84 MW publicly announced.

The combined generation capacity at Woolnorth of 138 MW will require significant upgrade of the Northern transmission system.

Heemskirk (Hydro Tasmania), with a total of 160 MW, has been publicly announced by Hydro Tasmania, which will be connected to Reece power station via a double circuit 220 kV line.

Musselroe (Hydro Tasmania), which is a publicly announced project of 140 MW, will be connected to Derby Substation. This would require transmission lines to Derby to be augmented.

Pacific Hydro has announced a proposal for a 100–140 MW project at Robbins Island, which will be added to the Woolnorth generation and would require an additional circuit into Smithton Substation.

3.12 System Standards

To a considerable degree, performance standards for transmission, and other entities, are documented in management reports agreed with the Regulator. Thus, where relevant, there are asset management plans, service plans, vegetation management plans and compliance plans.

Nevertheless, technical networks performance, as distinct from customer service, is prescribed in the TEC and, to a significant degree, reflects that provided in the NEC, especially in respect of Network Connection (Chapter 5) and Power System Security (Chapter 4). In these matters, there has over time been a considerable alignment with relevant NEM standards through a process of derogations to the TEC, which required compliance with the relevant standard over time. There are very few derogations remaining in respect of these matters.

The power system security and reliability standards for Tasmania are established by the Reliability and Network Planning Panel (RNPP), which is an independent body established by the TEC. There is a jurisdictional derogation in respect of frequency standards, which will carry into the NEM for two years, but then Tasmanian entities will be subject to the NEM reliability panel. There are other technical derogations, eg fault clearance times, which have also been authorised by the ACCC.

The security criteria for the Tasmanian transmission network has not been explicitly established and the Regulator is currently developing terms of reference for the RNPP in this regard.

3.13 Jurisdictional Technical Standards

3.13.1 Standards developed by the Reliability and Network Planning Panel

The Reliability and Network Planning Panel undertook a project to determine the performance measures and reporting formats for the Tasmanian power system. The final report of stage 1 of the project was completed in April 2003.

A workshop involving all of the entities was held in 2002 to consider industry performance objectives as set out in the Tasmanian Electricity Code (TEC). The workshop agreed the following system output measures in terms of reliability, quality and security:

Reliability

- energy not supplied
- customer minutes off supply
- system minutes off supply
- frequency of interruptions
- duration of interruptions
- number of momentary events

Quality

- number of voltage excursions outside standards
- flicker
- sag/over voltage
- voltage imbalance
- number of frequency excursions outside standards
- number of harmonic events outside standards

Security

- number of times not in secure operating state
- aggregate time duration not in secure operating state
- number of security directions issued

The following measures were agreed, after discussions with the relevant entities; System Control, Hydro Tasmania, Transend Networks and Aurora Energy.

Objective	Measures	Target 2000/01	Performance 2000/01	Performance 2001/02	Interstate Benchmark 2000/01
Maintain reliability of supply	Contribution to system global minutes off supply:	<19.77	51.48	9.11	1.18-7.86
	Direct connection points				
	Distribution connection points				
	Plant availability:				
	Transmission line circuit	98.80%	98.96%	99.17	
	Transformer circuit	98.50%	99.17%	99.13	
	Capacitor bank	98.50%	99.92%	98.83	
	Distribution System Connection points				
	Firm Connection Points				
	Average Planned outage duration	<20	19.1	0	
	Average Forced outage duration	<10	34.5	95	
	Average No of outages - Planned	<0.20	0.04	0	
	Forced	<0.20	0.14	0.38	
	No of momentary interruptions	N/A			
	Non-firm Connection Points				

Objective	Measures	Target 2000/01	Performance 2000/01	Performance 2001/02	Interstate Benchmark 2000/01
	Average Planned outage duration	<350	7088	2509	
	Average Forced outage duration	<25	88.0	63	
	Average No of outages - Planned	<0.70	0.90	0.38	
	Forced	<0.50	2.00	1.19	
	No of momentary interruptions	N/A			
	Direct Connection points				
	Firm Connection Points				
	Average Planned outage duration		0	155.3	
	Average Forced outage duration		77.7	35	
	Average No of outages - Planned		0	0.4	
	Forced		0.10	0.5	
	No of momentary interruptions	N/A			
	Non-firm Connection Points				
	Average Planned outage duration		5713	36.4	
	Average Forced outage duration		72.8	49	
	Average No of outages - Planned		0.38	0.13	
	Forced		1.50	0.75	
	No of momentary interruptions	N/A			

Objective	Measures	Target 2000/01	Performance 2000/01	Performance 2001/02	Interstate Benchmark 2000/01
Maintain reliability of supply (cont)	Generation System Connection points				
	Firm Connection Points				
	Average Planned outage duration	<15	51.8	306	
	Average Forced outage duration		4.2	0	
	Average No of outages - Planned	<0.10	0.105	0.11	
	Forced		0.05	0	
	No of momentary interruptions	N/A			
	Non-firm Connection Points				
	Average Planned outage duration	<480	1180	292	

Objective	Measures	Target 2000/01	Performance 2000/01	Performance 2001/02	Interstate Benchmark 2000/01
	Average Forced outage duration		20.7	5	
	Average No of outages - Planned	<0.50	1.39	0.48	
	Forced		0.22	0.26	
	No of momentary interruptions	N/A			
Maintain a secure system	No of Transmission Constraint Notices issued				
	LOR Notices (transmission) issued				
	LOR Notices (transmission) not avoided				
	Emergency Notices (transmission) issued				
Minimise cost of supply	Losses	N/A			
Maintain supply quality	No of times quality standards not met (No of complaints validated)				
Good operations management	No of operating errors	0			

N/A – Not available at this time

3.13.2 TEC Requirements

The Tasmanian Electricity Code (TEC), requires that network service providers must plan, design, maintain and operate their transmission networks and distribution networks to allow the transfer of power from generating units to customers with all facilities or equipment associated with the power system in service and may be required by a Code Participant under a connection agreement to continue to allow the transfer of power with certain facilities or plant associated with the power system out of service, whether or not accompanied by the occurrence of certain faults (called "credible contingency events") (s5.1.2.1).

Other requirements under Schedule 5 of the TEC are:

3.13.2.1 Frequency variations Capability (s5.1.3)

A Network Service Provider must ensure that within the power system frequency range 44.8 to 52 Hz all of its power system equipment will remain in service unless that equipment is required to be switched to give effect to load shedding in accordance with clause S5.1.10, or is required by the System Controller to be switched for operational purposes.

3.13.2.2 Magnitude of power frequency voltage (s5.1.4)

A Transmission Network Service Provider must plan and design extensions of its network and equipment for control of voltage such that the minimum steady state voltage magnitude on the transmission network will be 90 per cent of nominal voltage and the maximum steady state voltage magnitude will be 110 per cent of nominal voltage.

3.13.2.3 Voltage fluctuations (s5.1.5)

A Network Service Provider must include conditions in connection agreements in relation to the permissible variation with time of the power generated or load taken by a Code Participant to ensure that other Code Participants are supplied with a power frequency voltage which fluctuates to an extent that is less than the limit defined by the "Threshold of Perceptibility" in Figure 1 of Australian Standard AS2279 Part 4.

3.13.2.4 Voltage harmonics or Voltage notching distortion (s5.1.6)

A Network Service Provider must include conditions in connection agreements to ensure that the effective harmonic voltage distortion to any connection point will be limited to less than the level defined in Australian Standard AS2279 Part 2.

3.13.2.5 Voltage unbalance (s5.1.7)

A Transmission Network Service Provider must balance the phases of its network, and a Distribution Network Service Provider or a Customer must balance the current drawn in each phase at each of its connection points so as to achieve average levels of negative sequence voltage at all connection points that are equal to or less than the values set out in table below provided that at any nominal voltage the negative sequence voltage averaged over any one minute period must not exceed 2 per cent more frequently than once in any hour.

Nominal voltage (kV)	**Averaging time**	**Maximum negative sequence voltage (%)**	
		Normal conditions	**Single contingency**
>100	30 minutes 10 minutes	0.5 1.0	0.7 1.0
10-100	10 minutes	1.3	1.3
<10	10 minutes	2.0	2.0

3.13.2.6 Stability (s5.1.8)

The following criteria must be used by Network Service Providers for both planning and operation:

For stable operation of the power system, both in a satisfactory operating state and following any credible contingency events described in paragraph S5.1.2.1:

(a) the power system will remain in synchronism;

(b) damping of power system oscillations will be adequate; and

(c) voltage stability criteria will be satisfied.

3.13.2.7 Fault clearance times (s5.1.9)

Code Participants must ensure that the fault clearance times set out in table below for both main protections and for breaker fail protections are achieved for all connected plant owned by any Code Participant except as specifically advised by the Network Service Provider, and stated in a connection agreement.

	Maximum fault clearance time (milliseconds)		
System voltage (kV)	**Faulted end**	**Remote end**	**Breaker fail**
> 250 kV	100	120	250
100 kV - 250 kV	120	220	430
< 100 kV	As necessary to prevent *plant* damage and meet stability requirements		

3.13.2.8 Load shedding facilities (s5.1.10)

To maintain power system security the System Controller and each Network Service Provider must take all steps necessary to ensure that up to 60 per cent of the power system load at any time will be available for disconnection:

(a) under the control of underfrequency relays; and/or

(b) under manual or automatic control from the state control centre or by distribution system control centres; and/or

(c) under the control of undervoltage relays.

3.13.2.9 Automatic re-closure of overhead transmission lines (s5.1.11)

All overhead transmission lines forming part of a transmission network must have equipment for either three pole automatic reclose or single pole automatic reclose unless the relevant Transmission Network Service Provider and the System Controller agree otherwise.

3.13.2.10 Ratings for lines & equipment (s5.1.12)

For operational purposes each Transmission Network Service Provider must, on reasonable request, advise the System Controller of the maximum current that may be permitted to flow (under conditions nominated by the System Controller) through each transmission line or other item of equipment that forms part of its transmission network.

3.13.2.11 Remote monitoring equipment (s5.1.12)

Network Service Provider may be required to install remote monitoring equipment to monitor such data as current, voltage, real and reactive power etc to allow the System Controller to discharge its dispatch and power system security functions.

3.13.2.12 Obligations of Code Participants (5.2.1)

All Code Participants must maintain and operate (or ensure their authorised representatives maintain and operate) all equipment that is part of their facilities in accordance with good electricity industry practice and applicable Australian Standards.

3.14 Management Plans

Under the terms of the transmission licence held by Transend, it is required to develop four management plans and submit them to the Regulator every two years. These plans are:

compliance plan: a written plan developed by the entity outlining the procedures, practices and strategies for managing and auditing the entity's compliance with the ESI Act and any regulations made pursuant to the Act (the Regulations), the Code and the licences which must include (amongst other things) details of standards, indicators and targets for measuring the entity's compliance performance and must be in accordance with AS3806 compliance program;

asset management plan: a written plan developed by the entity outlining the procedures, practices and strategies for managing and auditing the asset management of the entity's operations;

service plan: a written plan developed by the entity outlining the procedures, practices and strategies for managing and auditing the reliability and performance of the entity's operations;

vegetation management plan: a written plan developed by the entity outlining the procedures, practices and strategies for managing and auditing control of vegetation near the entity's operations and the minimisation of fire hazard.

Each year, Transend is required to provide to the Regulator a report, which includes:

- details of the Licensee's actual performance against the standards, indicators and targets included in the management plans;
- if the Licensee's actual performance is below the targets included in a management plan, the reasons for the failure to meet the targets and strategies for achieving the targets in the future;

- projections of the Licensee’s future performance against the standards, indicators and targets included in the management plans;
- a description of the strategies adopted or to be adopted by the Licensee to achieve or exceed the performance targets included in the management plans; and
- details of the Licensee’s adherence to applicable Australian Standards.

3.15 Regulatory Reporter

Under the terms and conditions of the Transmission licence held by Transend, it is required to provide a report prepared by a reporter[21].

The reporter should, as a minimum:

- analyse documented procedures
- interview responsible staff
- analyse information systems
- analyse quality control procedures
- identify changes in systems and documented procedures
- analyse relevant data
- analyse a sample of cases/data
- in case of significant non-compliance, assess the entity’s plan to ensure future compliance.

The approach taken in Tasmania has been 'light handed' in that the Regulator has not sought to intervene in the day-to-day management of the entities. Rather, he seeks to ensure that all stakeholders are provided with sufficient information to properly assess the performance of the entities in meeting their regulatory obligations.

An important aspect of this ‘light handed’ approach to regulation is ensuring that all properly interested parties have reliable information as to the performance of the electricity entities against established performance criteria. To this end the licences provide that performance against the management plans of the entities will be subject to independent reporting. This reporting is designed to provide reliable base line data for performance assessment over time, and to enhance the effectiveness of the incentives provided by comparative reporting (competition by comparison) to improve service performance and introduce innovations. Reporting is also designed to enhance the licensees’ understanding of their compliance with key licence

[21] ***“reporter”*** means an appropriately qualified person engaged by the ***Licensee*** with the approval of the ***Regulator*** to report to the ***Regulator*** on compliance with and adequacy of ***management plans*** in accordance with terms of reference approved by the ***Regulator***.

conditions and provide a basis for implementing performance improvements and innovations.

The Regulator has issued a Guideline for the Regulatory Reporter.

3.15.1 Regulatory Reporter's Report – April 2003

The Terms of Reference given to the Regulatory Reporter under the most recent assignment specified the following objectives:

- to assess and report on compliance with licence management plan obligations since the last audit, in regards to:
  - the existence of procedures and/or processes to implement the identified obligations;
  - whether the procedures and/or processes are being followed; and
  - how to improve compliance to the extent that it is required.
- to report on generic compliance issues as outlined in the guidelines issued by the Regulator;
- to review the adequacy of existing licence management plans with regard to:
  - good electricity industry practice;
  - licence requirements and Regulatory Guidelines;
  - risk management principles;
  - the stated purpose of each plan;
  - and suggest improvements;
- to assess and report on the effectiveness of the reporting framework contained within the licence and the Regulatory Guidelines.