VENCORP SUBMISSION TO

ACCC

ELECTRICITY REVENUE CAP APPLICATION
FOR THE PERIOD
1 JANUARY 2003 TO 30 JUNE 2008

VICTORIAN ENERGY NETWORKS CORPORATION
LEVEL 2, YARRA TOWER
SIDDELEY STREET
WORLD TRADE CENTRE
VIC 8005

30 April 2002

VENCorp Vision

Victoria will achieve the most reliable and cost effective energy supply through competitive markets.

VENCorp Mission

VENCorp ensures the efficient and effective delivery of energy for the benefit of the Victorian community.

EXECUTIVE SUMMARY

Background

VENCorp performs various statutory and non-statutory functions in the gas and electricity industries in Victoria. One of the core functions undertaken by VENCorp is the provision of shared electricity transmission network services in Victoria. As the monopoly provider of these services, VENCorp is subject to economic regulation under the National Electricity Code (the "Code"). VENCorp has been requested to submit, for review by the ACCC, forecasts of the costs that are expected to be recovered through Transmission Use of System (TUoS) charges over the regulatory control period from 1 January 2003.

In accordance with its responsibilities under the Code, the ACCC has stated it will review these estimated costs and make a determination as to the appropriate revenue cap to be applied to the prescribed transmission services provided by VENCorp for the regulatory control period from 1 January 2003. The applicable provisions of the Code are set out in Chapter 6 and clause 9.8.4.

This submission sets out the information that the ACCC requires in order to determine the revenue cap that will apply to VENCorp for the regulatory period commencing on 1 January 2003.

Victoria's unique transmission arrangements

The ownership, governance and organisational arrangements within the Victorian transmission sector are unique insofar as:

- VENCorp is the only Transmission Network Service Provider (NSP) in Australia which is constituted as a not-for-profit organisation;
- VENCorp owns no transmission assets, and has no commercial interest in developing or owning transmission assets;
- VENCorp's corporate objectives explicitly require the organisation to deliver its services, and to perform its functions, in a commercially-neutral and cost-effective (value-maximising) manner; and
- VENCorp's Board has in place a number of processes, including internal and external scrutiny of forecast and actual cost performance, to ensure that budgeted and actual cost performance are consistent with best practice.

VENCorp considers that the structural, organisational and governance arrangements that apply within the Victorian electricity transmission sector should, of themselves, provide the ACCC and other stakeholders with a considerable degree of comfort that:

- the costs incurred by VENCorp in undertaking its network service provision, network planning and related functions reflect efficient costs;
- the transmission investment decisions made by VENCorp are efficient, and are based on the best available information and analysis at the time the decisions are made; and
- given the opportunities for increased competition for construction and ownership of new transmission assets, the costs of assets that are created pursuant to a VENCorp investment decision reflect efficient practice.

Applicability of Part B of Chapter 6 of the National Electricity Code to VENCorp

The regulatory principles set out in Part B of Chapter 6 generally reflect an assumption that transmission network service provision within a region will be undertaken by a single commercial entity that is responsible for both:

- network planning and investment decision-making (VENCorp's sole responsibility in Victoria); and
- network asset ownership (the function of SPI PowerNet and other commercial asset owners).

Notwithstanding the ACCC's intention to apply the principles of Part B of Chapter 6 of the Code in its review of VENCorp's budgeted costs, it is noted that clause 9.8.4(a)(2) of the Code states that in the case of any inconsistency between the Victorian electricity transmission regulatory arrangements and the Code, the Victorian arrangements prevail. The Victorian regulatory arrangements explicitly recognise and accommodate the unique organisational arrangements that exist within the Victorian transmission sector.

Given the provisions of clause 9.8.4(a)(2) and Part B of Chapter 6 of the Code, VENCorp considers that there is a need to clarify:

- the respective regulatory roles and powers of the ACCC and the Victorian Essential Services Commission; and
- the on-going applicability of the Victorian electricity transmission regulatory arrangements within the framework set out in the Code.

Consequently, the Victorian Department of Natural Resources and Environment is working closely with VENCorp to develop Code change proposals aimed at clarifying the regulatory arrangements applying to VENCorp under the Code from 1 January 2003.

Proposed regulatory period

In order to align each regulatory year with financial years as defined in the Code, VENCorp proposes that the regulatory control period be for a period of five and a half years from 1 January 2003 to 30 June 2008. The first six months of this period from 1 January 2003 would effectively be a transition period from the determination made by the ACCC under the Victorian Electricity Supply Tariff Order for the financial year ending 30 June 2003.

Proposed revenue cap arrangements

VENCorp considers that a revenue cap for the forthcoming regulatory period would not be inconsistent with the provisions of clause 9.8.4(a)(2) of the Code, provided that the revenue cap contains mechanisms to ensure that:

- VENCorp is able to adjust, subject to approval from the ACCC, its TUoS charges once each year to adjust for any over-recovery or under-recovery of revenues from previous years, which may arise for any reason including variations between actual operating costs and forecasts of operating costs used by the ACCC to set VENCorp's revenue cap; and

- VENCorp is able to adjust TUoS charges once each year to reflect and recover the costs of new network augmentations in the year in which these assets enter service, regardless of whether or not the actual costs of these augmentations have been included in the forecasts of costs used by the ACCC to set VENCorp's revenue cap, subject to the requirement that any new augmentation is demonstrated to be economically justified through the application of the Regulatory Test.

VENCorp's cost structure

VENCorp recovers the costs associated with its statutory electricity transmission-related functions through Transmission Use of System charges. Over the five and a half year period commencing in January 2003, these costs will consist of the following elements:

- VENCorp's own actual operating and capital costs (as set out in Section 6 of this submission); and

- Payments for provision of bulk transmission network services to asset owners as follows (and as set out in Section 7 of this submission):

    - payments made by VENCorp to SPI PowerNet for provision by SPI PowerNet of Prescribed Services (Note that the charges levied by SPI PowerNet for these services will be subject to separate regulation by the ACCC);

- payments made by VENCorp to SPI PowerNet and other Transmission NSPs for bulk transmission services provided under existing contracts to VENCorp; and

- the costs of payments that VENCorp will make to providers of new augmentations that will be required over the course of the five and a half year period to maintain adequate levels of transmission system reliability and performance.

VENCorp's forecast of total required revenue

The table below provides a summary of the main components of VENCorp's estimated total revenue requirement for the period ending 30 June 2008. The values are in real dollars as at March 2002 and exclude GST.

It is noted that VENCorp's own operational expenditure averages just 11 cents per MWh (in real terms) over the period from 2002/03 to 2007/08. This cost represents less than 0.1% of the average cost of electricity to a typical Melbourne domestic customer.

Overall Revenue Requirement	**Forecast Financials (in 2002 $M) for Year ending 30 June**					
	2003 (6 months)	**2004**	**2005**	**2006**	**2007**	**2008**
Net Operational Expenditure	2.7	5.4	5.5	5.9	5.9	6.1
Committed Annual Augmentation charges	5.9	10.9	10.6	10.2	9.7	9.5
Planned Annual Augmentation charges	0.2	3.6	7.5	12.2	15.6	17.2
Total VENCorp forecast expenditure	**8.8**	**19.9**	**23.6**	**28.3**	**31.2**	**32.8**
SPI PowerNet Prescribed Service charges[1]	122.1	238.4	237.5	234.8	232.9	231.7
Total costs to be recovered through TUoS charges by VENCorp	**130.9**	**258.3**	**261.1**	**263.1**	**264.1**	**264.4**
Energy (GWh)[2]	24,395	50,062	50,995	52,003	52,835	53,628
Victorian TUOS charges ($/MWh)	5.4	5.2	5.1	5.1	5.0	4.9

These cost forecasts are based on assumptions that:

[1] SPI PowerNet's estimated prescribed services charge to VENCorp is based on SPI PowerNet's revenue cap application to the ACCC, an allocation to VENCorp of 86% of total charges, a reduction based on expected availability incentive payments, and an annual CPI estimate of 3.1% as used by SPI PowerNet to express as real 2002 dollars.

[2] The energy value is on a generator sent out basis. The value shown for year ending June 2003 is 50% of the full year value.

- the present service standards and network performance standards will continue to apply over the forthcoming regulatory period; and
- the network planning standards and investment criteria presently applied by VENCorp will continue to apply over the forthcoming regulatory period.

In addition, the cost forecasts set out in this submission are based on other key assumptions relating to a number of key factors including:

- demand growth, and the timing, magnitude and cost of future network augmentations;
- the methodology for calculating annual charges for new network augmentations;
- the ACCC's determination in relation to SPI PowerNet's allowed rate of return (WACC), and the level of operations and maintenance costs that SPI PowerNet will be permitted to recover through its regulated charges for provision of prescribed services; and
- the outcomes of competitive tenders for new augmentations.

Actual outcomes in the future may vary significantly from those assumed by VENCorp in its forecasts. Accordingly, VENCorp's forecasts of its total annual costs to be recovered through TUoS charges are subject to change. As noted above, VENCorp has proposed that its revenue cap be structured in a manner that enables VENCorp to adjust its annual TUoS charges, subject to approval from the ACCC, to reflect any variations between actual and forecast costs.

Network planning standards and investment decision criteria

Augmentation costs will be driven by the planning standard that is applied. VENCorp applies a probabilistic (as opposed to deterministic) approach in its network investment decision analysis. VENCorp's approach is consistent with the requirements of the regulatory test for new interconnectors and network augmentations. In 2001, VENCorp undertook a detailed review of its network planning and investment criteria. The review involved consultation with a wide range of stakeholders. The review concluded that VENCorp should continue to apply a probabilistic approach to network planning and investment decision analysis.

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1 PURPOSE OF THIS DOCUMENT

VENCorp performs various statutory and non-statutory functions in the gas and electricity industries in Victoria. One of the core functions undertaken by VENCorp is the provision of shared electricity transmission network services in Victoria. As the monopoly provider of these services, VENCorp is subject to economic regulation under the National Electricity Code (the "Code"). VENCorp has been requested to submit, for review by the ACCC, forecasts of the costs that are expected to be recovered through Transmission Use of System (TUoS) charges over the regulatory control period from 1 January 2003.

In accordance with its responsibilities under the Code, the ACCC has stated it will review these estimated costs and make a determination as to the appropriate revenue cap to be applied to the prescribed transmission services provided by VENCorp for the regulatory control period from 1 January 2003. The applicable provisions of the Code are set out in Chapter 6.

Part B of Chapter 6 of the Code requires, inter alia, that:

- in setting the revenue cap, the ACCC must have regard to the potential for efficiency gains in expected operating, maintenance and capital costs, taking into account the expected demand growth and applicable service standards; and
- the regulatory regime should seek to achieve an environment which fosters efficient use of existing infrastructure, efficient operating and maintenance practices, and an efficient level of investment.

In this context, the ACCC has indicated that it will be required to be assured of the adequacy, efficiency and appropriateness of the O&M expenditure stated by VENCorp as being necessary to meet its present and future transmission service requirements.

In light of this requirement, the purpose of this document is to:

- provide an overview of the role, functions and powers of VENCorp in relation to the provision of electricity transmission and related services;
- describe the institutional and governance arrangements that exist in the Victorian electricity transmission sector;
- explain the implications of these arrangements for the regulation and recovery of VENCorp's electricity transmission-related costs;
- describe the various components and drivers of the total cost that VENCorp must recover through TUoS charges; and
- provide a detailed substantiation of VENCorp's total budgeted costs for the regulatory control period from 1 January 2003.

2 VICTORIA'S ELECTRICITY TRANSMISSION SECTOR

2.1 Victorian Transmission Network Characteristics

The Victorian transmission network consists of various transmission lines that link power stations to the distribution system. The transmission lines operate at voltages of 500kV, 330kV, 275kV, and 220kV, with the 500kV transmission lines transporting electricity from generators in the Latrobe Valley in Victoria's east to Melbourne, and on to the major smelter load and interconnection with South Australia to the west . The 220kV lines service the rest of Victoria, while the 330kV lines interconnect with New South Wales, and 275kV lines interconnect with South Australia (refer Figures 2.1 and 2.2).

The electricity transmitted through the high voltage transmission lines is converted to lower voltages at terminal stations where it then enters the distribution system. There are a total of 36 terminal stations around Victoria with the majority transmitting at voltages of 220kV. The total distance covered by transmission lines is approximately 6000 kilometres.

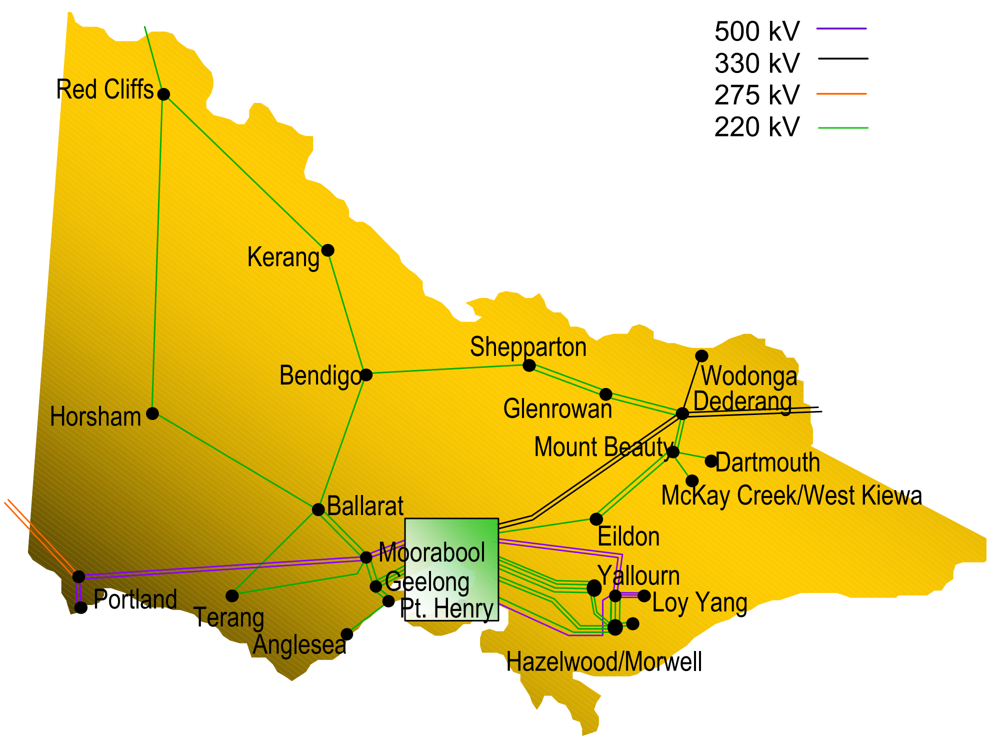

Figure 2.1 - Victorian Transmission Network

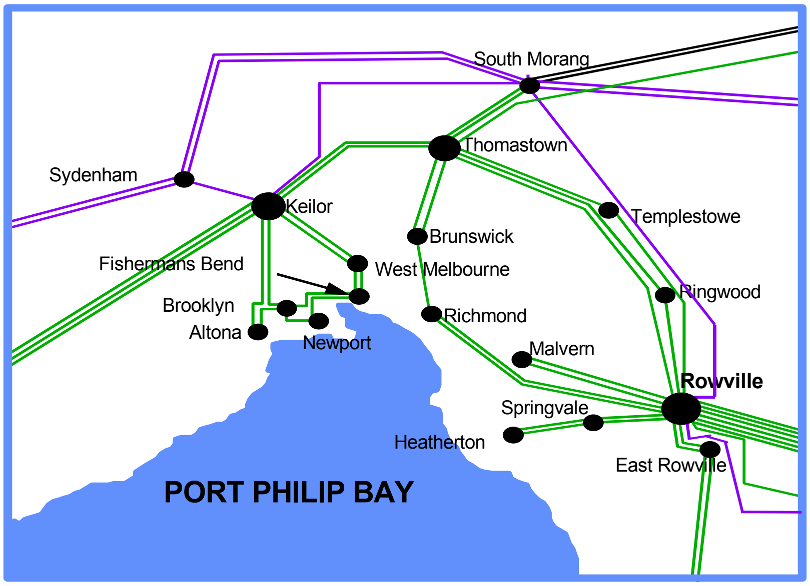

Figure 2.2 - Melbourne Metropolitan Transmission Network

Load forecasts and the requirement for the reliability of the transmission network to be maintained at an economically efficient level, are key determinants of Victoria's future transmission requirements. For a medium economic growth scenario, Victorian energy consumption[3] is forecasted to rise from 48,790 GWh in 2002-03 to 53,628 GWh in 2007-08, with the forecasted maximum summer demand expected to increase from 9,302 MW in 2002-03 to 10,670 MW in summer 2007-08, based on 10 percentile temperature expectations.

The historical load curve, as shown in Figure 2.3 displays the percentage of time that demand is above a certain MW level on an annual basis. From this it is noted that typically the top 15% of maximum loads on the system occur for 1% of the time, and that, excluding the highest and lowest demand levels, about 90% of the loads for the year fall within a comparatively narrow range of about 2000MW. The system load is becoming increasingly more summer and winter peaking in nature giving rise to an increasing difference between average and peak load.

[3] Energy at generator terminals

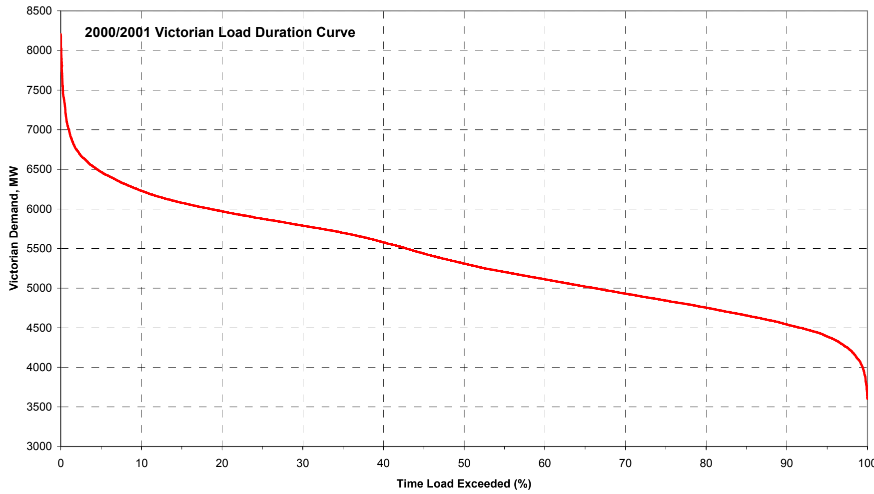

Figure 2.3 – 2000-01 Annual Load Duration Curve

2.2 Structure and organisation of the Victorian electricity transmission sector

Under arrangements put in place by the Victorian Government in 1993, various responsibilities for electricity transmission are separated between VENCorp, the transmission asset owners (principally SPI PowerNet[4]) and the users of the transmission system as follows:

- VENCorp, as the monopoly provider of transmission use of system services, plans and directs the augmentation of the "shared transmission network".[5] However, VENCorp does not own any transmission assets itself. VENCorp procures "network services" from the owners of transmission assets under "Network Agreements", and uses these network services to provide "use of system services" to network users under "Transmission Use of System Agreements".

- The transmission system users (distribution businesses and main system generators) are responsible for planning and directing augmentation of the transmission connection assets that connect their facilities to the shared transmission network.

- The role of transmission network asset owners, such as SPI PowerNet, is limited to that of "bulk network service providers". Services provided by SPI PowerNet are in accordance with the requirements of the transmission planners (namely, VENCorp in respect of the "shared network", and users in respect of their transmission connection facilities).

Under the terms of their transmission licences, SPI PowerNet cannot augment the Victorian transmission system unless that augmentation is pursuant to an agreement with VENCorp, a distributor, a generator or a customer.

4 Ownership of all Victorian transmission assets as at 1993 was vested in PowerNet. That organisation is now known as SPI PowerNet.

5 The "shared transmission network" is the Victorian transmission system, excluding the transmission facilities that connect the distribution networks and the generators to the high voltage network; and excluding market network service providers.

These arrangements are unique to Victoria. The rationale for these arrangements is as follows:

- Responsibility for transmission investment decision-making is separated from the transmission asset ownership role. Decisions to invest will therefore be based on an objective assessment by VENCorp of overall costs and benefits.[6] This removes the risk of transmission augmentations being undertaken by a party (i.e. the asset owner) that may have a commercial interest in expanding its revenue base, through inefficient augmentation. The aim of this feature of the Victorian arrangements is to maximise the likelihood that VENCorp's decision-making leads to the optimal level of transmission investment taking place.

- The parties responsible for planning and directing transmission augmentation (i.e. VENCorp for the shared transmission network and the Distribution Businesses for connection assets) have the opportunity to competitively source new investment[7]. This, in turn, provides a means of introducing competition into the design, construction, maintenance, financing and long-term ownership of transmission infrastructure, leading to reduced costs. The introduction of competition ensures that once an investment decision is made, it will be implemented as efficiently as possible.

Figure 2.4 depicts the commercial arrangements for the provision of electricity transmission services in Victoria, and each party's planning and other responsibilities.

[6] VENCorp's governance arrangements reinforce it independence and impartiality in network investment decision analysis. Those arrangements are described in detail in Section 3.5 below.

[7] In VENCorp's case, VENCorp is obligated under its Transmission Licence to source augmentations on a contestable basis unless otherwise approved by the Essential Services Commission.

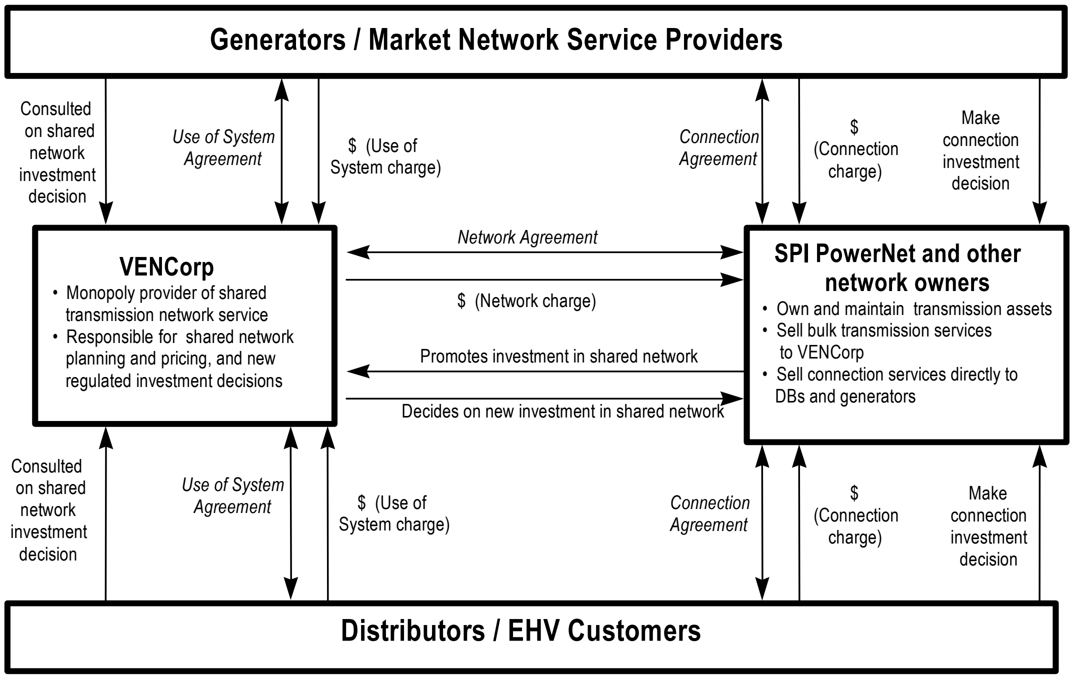

Figure 2.4 – Commercial arrangements for the provision of electricity transmission services in Victoria

Figure 2.5 depicts the flow of financial payments for the provision of electricity transmission services in Victoria.

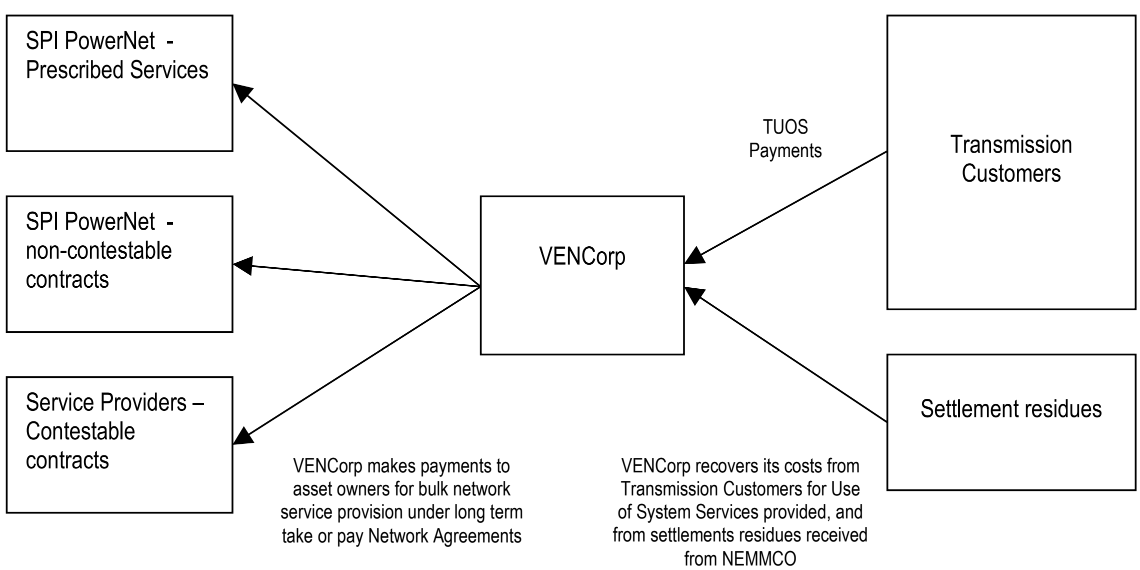

Figure 2.5 – Transmission Services Financial Flows in Victoria

2.3 VENCorp's role and powers in the Victorian electricity industry

As noted above, VENCorp is the monopoly provider of shared electricity transmission network services in Victoria. It also has statutory responsibilities to plan and direct the augmentation of the shared transmission network. There are a number of legislative, regulatory and contractual instruments that define VENCorp's role, functions and powers as the planner and monopoly provider of shared electricity transmission network services. These instruments include:

- Electricity Industry Act;
- VENCorp's Electricity Transmission Licence;
- National Electricity Code;
- Victorian System Code;
- Use of System Agreements between VENCorp and Participants; and
- VENCorp's Statement of Corporate Intent

Attachment 1 provides a summary of the relevant provisions contained in these instruments. Section 3 of this document discusses in more detail the applicability to VENCorp of the Code's economic regulatory principles. The specific functions undertaken by VENCorp are listed in Section 2.4 below.

2.4 Electricity-related functions undertaken by VENCorp

In accordance with the provisions of the various instruments listed in Section 2.3 above, the specific electricity-related functions undertaken by VENCorp are:

(a) provision of shared electricity transmission network services to customers under long term service contracts;

(b) procurement of bulk electricity transmission services from network owners under long term contracts;

(c) planning and directing the augmentation of the shared electricity transmission network to meet existing and expected future needs of customers;

(d) provision of services and support to NEMMCO pursuant to the National Electricity Code to ensure secure operation of the power system;

(e) management of electricity emergencies via the Responsible Officer role;

(f) technical compliance monitoring;

(g) provision of information to facilitate decisions for economically efficient investment in the electricity industry;

(h) the facilitation of Demand-side management initiatives within Victoria; and

(i) administration of the Victorian Governments' Special Power Payments scheme to rural and regional domestic consumers.

Each of these functions (with the exception of facilitating demand-side management initiatives, and administering the Special Power Payments scheme) are functions required of a Transmission Network Service Provider in the National Electricity Market. Accordingly, the costs of these functions are recovered by VENCorp through TUoS charges.[8]

2.5 Governance of VENCorp's electricity transmission functions

As noted in Section 2.3 above, VENCorp derives its electricity transmission planning powers from the Electricity Industry Act, and its transmission licence issued by the Essential Services Commission pursuant to that Act.

VENCorp is governed by a Board of up to ten directors (including the Chairman) appointed by the Governor-in-Council (as specified in Section 165 of the Gas Industry Act 2001). The Board approves the Corporation's goals and direction, considers strategic plans, approves performance targets and provides overall policy guidance. It ensures that appropriate policies, procedures and associated internal controls are in place to manage risks.

While the Board has a number of Directors drawn from participants in the gas and electricity industries, the Directors are regarded as independent. VENCorp defines "independent" as independent of the executive management and of the business and other relationships which could otherwise detract from the Director's ability to act impartially in the corporation's best interests.

The Board approves the Corporation's goals and directions, considers strategic plans, approves performance targets and provides overall policy guidance. The Board ensures that appropriate policies, procedures and associated internal controls are in place to manage risks.

The VENCorp Board has four committees, one of which is the Safety and Emergency Management Committee. This Committee ensures that VENCorp has the necessary programmes and processes in place to fulfil its responsibilities for safety and management of emergencies, and that VENCorp observes its statutory compliance with safety regulations.

Another Board committee is the Audit and Risk Committee which assesses and reviews the internal and external audits and is also responsible for assessing the adequacy of VENCorp's accounting, financial and operating controls, and risk management strategy. This Committee recommends the appointment of the internal auditors, the scope of the audit and the setting of fees, and also oversees the Market Operations Audit.

The other Board committees are the Policy Development Committee and the Remuneration Committee.

[8] Details of the components of the costs recovered through TUoS charges are set out in Section 5.

One of the basic functions of the VENCorp Board is to ensure that VENCorp executes its role as Victorian transmission network planner and transmission network service provider in an objective, independent, consultative and transparent manner, so as to maximise net benefits to industry participants (including end consumers) as a whole. Given that VENCorp's transmission planning decisions can impact on the financial position of individual market participants or groups of participants, the VENCorp Board is constituted as the forum in which the potentially conflicting interests of market participants and other stakeholders are independently assessed, to meet the ultimate objective of providing the optimal level of transmission capability at least cost.

VENCorp operates on a not-for-profit basis. It has no commercial interest in owning or developing transmission network assets.

3 APPLICABILITY OF THE NATIONAL ELECTRICITY CODE TO VENCORP

3.1 ACCC's approach to setting VENCorp's revenue cap for 2003 to 2008

The ACCC has noted that Part B of Chapter 6 of the Code requires, inter alia, that:

- in setting a revenue cap to apply to a transmission NSP, the ACCC must have regard to the potential for efficiency gains in expected operating, maintenance and capital costs, taking into account the expected demand growth and applicable service standards; and
- the regulatory regime should seek to achieve an environment which fosters efficient use of existing infrastructure, efficient operating and maintenance practices, and an efficient level of investment.

In this context, the ACCC indicated that it will be required to be assured of the adequacy, efficiency and appropriateness of the O&M expenditure stated by VENCorp as being necessary to meet its present and future transmission service requirements.[9]

VENCorp accepts that the ACCC requires such assurances to be provided. VENCorp considers that the structural, organisational and governance arrangements that apply within the Victorian electricity transmission sector should, of themselves, provide the ACCC with a considerable degree of comfort that:

- the costs incurred by VENCorp in undertaking its network service provision, network planning and related functions reflect efficient costs;
- the transmission investment decisions made by VENCorp are efficient, and are based on the best available information and analysis at the time the decisions are made; and
- given the opportunities for increased competition for construction and ownership of new transmission assets, the costs of assets that are created pursuant to a VENCorp investment decision reflect efficient practice.

Notwithstanding the ACCC's intention to apply the principles of Part B of Chapter 6 of the Code in its review of VENCorp's budgeted costs, it is noted that clause 9.8.4(a)(2) of the Code states that in the case of any inconsistency between the Victorian electricity transmission regulatory arrangements and the Code, the Victorian arrangements prevail.

Given this, VENCorp considers that there is some confusion regarding:

- the respective regulatory roles and powers of the ACCC and the Victorian Essential Services Commission; and
- the on-going applicability of the Victorian electricity transmission regulatory arrangements within the framework set out in the Code.

[9] Refer to the document produced in March 2002 by the ACCC, titled *Consultancy Terms of Reference VENCorp Operating Expenditure Review.*

The diagram below provides a high-level overview of the principal matters that are subject to regulatory oversight within the Victorian transmission sector, and respective roles of the ACCC and the Essential Services Commission. The diagram indicates that the NEC is based on an assumption that transmission network service provision within a region will be undertaken by a single entity that is responsible for both:

- network planning and investment decision-making (VENCorp's responsibility in Victoria); and
- network asset ownership (SPI PowerNet's function).

As a result, matters relating to the definition of the respective roles of VENCorp and SPI PowerNet, and the inter-relationships between these two entities are not adequately addressed under the NEC.

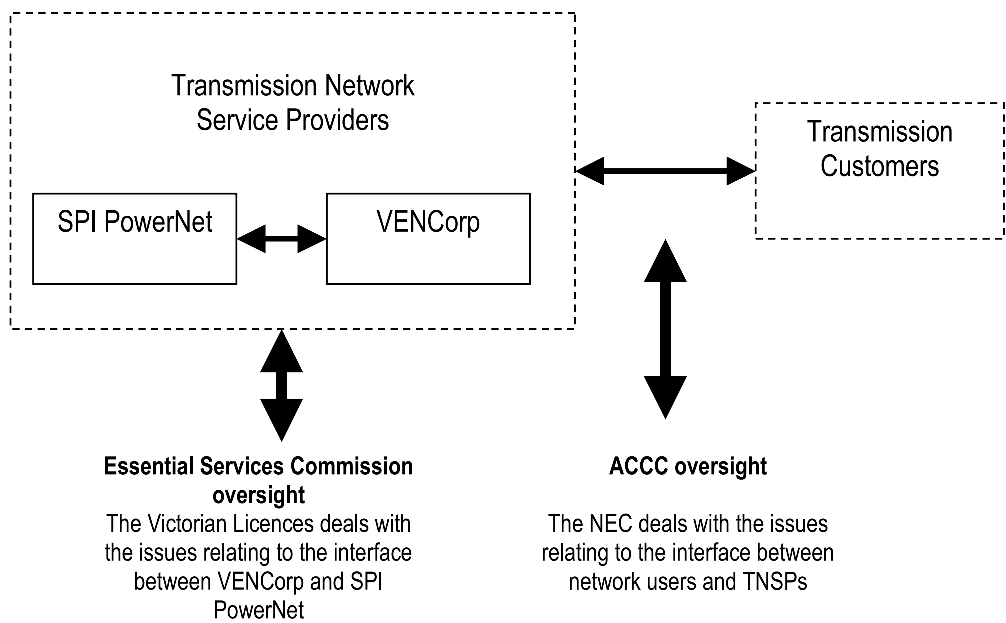

Figure 3.1 – Overview of regulatory roles for the Victorian transmission sector

As a consequence of these factors, the Victorian Department of Natural Resources and Environment is working closely with VENCorp to develop Code change proposals aimed at clarifying the regulatory arrangements applying to VENCorp under the Code from 1 January 2003. In the meantime, as noted above, VENCorp accepts the need for the ACCC to be provided with information demonstrating that the costs to be recovered by VENCorp over the regulatory control period commencing in January 2003 reflect efficient operating costs and an efficient level of investment.

Given the present lack of clarity regarding the revenue regulatory arrangements that will apply to VENCorp from January 2003, Section 3.2 below sets out the key features of the Victorian electricity transmission regulatory arrangements. It is VENCorp's view that the ACCC's adoption of the principles inherent in the "key features" described below would be consistent with the requirements of clause 9.8.4(a)(2) of the Code.

3.2 Key features of the Victorian regulatory regime

The "Victorian transmission regulatory arrangements" are defined in clause 9.8.3(b) of the Code. In summary, the key features and principles that underpin the regime, and which remain applicable for the future, are as follows:

1. VENCorp is permitted to recover, through its aggregate annual TUoS charges, an amount of revenue that equals VENCorp's statutory electricity transmission-related costs, being the sum of VENCorp's transmission-related actual operating costs and all network charges payable by VENCorp to the owners of transmission network assets and the providers of network support services.

2. VENCorp's aggregate annual TUoS revenue is to be determined by VENCorp on a full cost recovery but no operating surplus basis.

3. In determining and reviewing the proposed aggregate annual TUoS revenue, VENCorp and the regulator, respectively, must take into account:

   (a) VENCorp's functions under the Electricity Industry Act, the National Electricity Code and its Transmission Licence; and

   (b) any difference between the amount recovered by VENCorp in preceding years through TUoS charges, and VENCorp's actual transmission-related costs plus network charges payable (allowing for forecast errors in annual operating costs, and forecast errors in annual network charges due to the commissioning of unforeseen excluded services capital expenditure).

4. The regulator will approve the recovery, through TUoS charges, of VENCorp's aggregate statutory electricity transmission-related costs, provided that the conditions listed in the preceding three paragraphs are met.

3.3 Key principles to apply to VENCorp's revenue regulation for 2003 to 2008

It is noted that the key features and principles listed in Section 3.2 above are somewhat different to those set out in Part B of Chapter 6 of the Code. However, VENCorp is of the view that Part B of Chapter 6 was not intended to be applied to a commercially-neutral (not-for-profit) Network Service Provider (such as VENCorp). Attachment 2 sets out the reasons for VENCorp's view in further detail.

It is also noted that the principles listed in Section 3.2 are consistent with:

- VENCorp's not-for-profit status in the electricity industry;
- VENCorp's open and transparent manner of undertaking its statutory roles;
- the independent and commercially-neutral role played by VENCorp in planning and directing the augmentation of the Victorian shared network; and

- the governance arrangements that apply to VENCorp.

VENCorp's not-for-profit status and corresponding governance arrangements are not expected to change over the regulatory period commencing in January 2003. Given this consideration, and the apparent intent of clause 9.8.4(a)(2) of the Code, VENCorp believes that the key features described in Section 3.2 above should be embodied in the approach applied by the ACCC in making its revenue cap determination for VENCorp, to apply for the regulatory period from January 2003.

It is noted that the Victorian transmission regulatory arrangements provide for the annual review and approval of VENCorp's aggregate statutory electricity transmission-related costs. The Victorian arrangements therefore, in effect, provide for an annual revenue cap. It is understood that the ACCC wishes to implement a revenue cap that would apply to VENCorp for a five year regulatory period (in accordance with the requirements of clause 6.2.4(b) of the Code.)

VENCorp considers that a revenue cap for the regulatory period would not be inconsistent with the key features and principles of the Victorian transmission regulatory arrangements, provided that the revenue cap contains mechanisms to ensure that:

- VENCorp is able, subject to approval from the ACCC, to adjust its TUoS charges each year to adjust for any over-recovery or under-recovery of revenues from previous years, which may arise for any reason including variations between actual operating costs and forecasts of operating costs used by the ACCC to set VENCorp's revenue cap; and

- VENCorp is able to adjust TUoS charges once each year to reflect and recover the costs of new network augmentations in the year in which these assets enter service, regardless of whether or not the actual costs of these augmentations have been included in the forecasts of costs used by the ACCC to set VENCorp's revenue cap, subject to the requirement that any new augmentation is demonstrated to be economically justified through the application of the Regulatory Test.

3.4 Regulatory Control Period

Clause 6.2.4 of the Code requires a regulatory control period of not less than five years. In order to align each regulatory year with financial years as defined in the Code, VENCorp proposes that the regulatory control period be for a period of five and a half years from 1 January 2003 to 30 June 2008.

The first six months of this period from 1 January 2003 would effectively be a transition period from the determination made by the ACCC under the Victorian Electricity Supply Tariff Order for the financial year ending 30 June 2003.

4 VENCorp's VISION, MISSION AND VALUES

4.1 VENCorp's Vision, Mission and Values

VENCorp was officially established on 11 December 1997 – its major initial focuses being the operation of Victoria's gas transmission system, and the development and introduction of Australia's first gas spot market. Just prior to the start of 1999/2000, VENCorp formally integrated responsibility for Victoria's electricity transmission services function from the Victorian Power Exchange.

VENCorp's Vision and Mission Statements, Values and Strategic Core Drivers and Objectives were originally developed in 2000 to represent the functions and ambitions of the organisation. These have been reviewed annually and it is VENCorp's view that the statements continue to be highly appropriate.

There has been considerable effort expended in development of a new culture for and within VENCorp, consistent with its Core Drivers and corporate Values. Ownership of the "drivers" is considered essential to improve and cement management/staff relationships. Each Department and individual employee has a business or performance/development plan that is linked to the corporate Core Drivers and Objectives. A committed staff will ensure VENCorp wins the respect required in the industries it serves.

4.1.1 VENCorp Vision Statement

The VENCorp vision looks beyond its immediate tasks of providing cost efficient, safe and reliable services to the energy industry by ensuring that:

Victoria will achieve the most reliable and cost effective energy supply through competitive markets.

4.1.2 VENCorp Mission Statement

To achieve this vision, the VENCorp mission ensures that the benefits are focussed on the entire Victorian community including industry participants.

VENCorp ensures the efficient and effective delivery of energy for the benefit of the Victorian community.

4.1.3 VENCorp Values

To achieve its Vision and Mission, VENCorp relies on a dedicated and highly skilled staff. The following values have been identified as contributing significantly to the VENCorp Vision and Mission.

- ***Innovation:***

VENCorp plays key roles in two dynamic industries and the requirements made of it by stakeholders and customers are considerable. Apart from commitment to delivering services, VENCorp requires its people to be innovative – constantly seeking new and improved ways of effectively and efficiently meeting stakeholder expectations and delivering services. Adopting the best teamwork principles, introducing new developments and techniques, identifying new opportunities, seeking continuous improvement, critically challenging current practices and removing the fear of failure will assist in "stamping" VENCorp and its people as innovative.

- ***Honesty and Integrity***

VENCorp firmly believes that honesty and integrity openly displayed across all management and staff levels within the organisation are very important in developing a VENCorp which people will be happy to work for. Because of its important and diverse roles, VENCorp requires particular skills and highly motivated people. Honesty and integrity are also crucial to build required relationships with stakeholders and customers. Openness and transparency across all levels of the organisation, challenging and refusing to accept half-truths and basic candour will assist in ensuring that honesty and integrity are key ingredients within the VENCorp culture.

- ***Respect for people***

VENCorp's greatest asset is its people. VENCorp needs very committed and skilful people to meet all its obligations and gain the respect of the industries in which it operates. Training programmes, staff development programmes and succession planning are just some of the initiatives VENCorp is putting in place for its people. Policies and a Code of Conduct are in place to ensure that everyone in the organisation knows what is expected of them and each other. Respect for people is not "rocket science" and includes such simple courtesies as arriving on time for meetings, diverting phones, turning off mobile phones in meetings and cleaning up one's "mess". VENCorp wishes all its staff to achieve an appropriate and satisfactory work/life balance.

- ***Accountability***

VENCorp and all its people – management and staff – must be accountable for everything they do. Proper accountability in all VENCorp's dealings with its stakeholders is a key to successful relationships. Similarly accountability is very important from an internal perspective, and will assist in developing and cementing the appropriate degree of trust and respect which must exist between management and staff at all levels if the organisation is to succeed. Meeting deadlines, achieving the required quality of work and accepting accountability are just some of the attributes amounting to good general accountability for what goes on.

- ***Teamwork***

As indicated previously, VENCorp places great importance on the need for teamwork throughout the organisation. Working together, sharing of important information and "dancing to the same tune" are very important requirements if VENCorp is to achieve its programme of continuous improvement and achieving best practice. Sharing information, utilising the "team brain", supporting colleagues, making decisions "as one" and breaking down the "silo" or the closed departmental mentality all contribute to a successful teamwork culture.

4.1.4 Strategic Core Drivers

The Strategic Core Drivers of *Our People, Sound Commercial Management, Stakeholder Management and Services* and *Reliable Systems* continue to be critically important to ensure VENCorp moves forward to be an industry leader and facilitator of market evolution.

- ***Our People***

The strategic goal for the organisation continues to be the development of capable staff committed to the delivery of VENCorp's services. To achieve this and to underline its respect for its people, VENCorp is implementing appropriate training and employee development programmes across the organisation, and developing succession plans for key positions.

- ***Sound Commercial Management***

It is VENCorp's aim to be recognised by its large and diverse stakeholder group as a commercially responsible organisation. Actions to achieve this recognition include implementing best practice budget and cost control processes in all areas including project and contract management.

- ***Stakeholder Management and Services***

Developing good relationships with all stakeholders is a key core driver for VENCorp. It recognises that delivery of best practice service will enhance its reputation and meet stakeholder expectations. Developing a clear understanding of VENCorp's roles and responsibilities, and ensuring that all services are appropriately costed, delivered on time and to the required quality level, continue to be priority tasks.

The Government has assigned VENCorp the delivery of critical components of full gas retail contestability – they include the retail rules and a number of IT systems - and the successful completion of the tasks is crucial as the organisation seeks to enhance its reputation and standing within Government and the energy industry. A failure to deliver will be a serious set-back for the organisation and its development.

- ***Reliable Systems***

Without reliable systems, VENCorp's bid to enhance its reputation and develop excellent stakeholder relationships would be destroyed. Meeting energy demand safely without supply or market disruption due to system failures or inadequacies is the goal. To get there, VENCorp maintains system reliability and availability, and annually updates its IT strategy.

5 OVERVIEW OF VENCORP'S COST STRUCTURE

As noted above, VENCorp recovers the costs of its statutory electricity transmission-related functions through TUoS charges.

VENCorp's statutory electricity transmission-related costs over the five and a half year period commencing in January 2003 will consist of the following elements:

a) VENCorp's own actual operating and capital costs (as set in Section 6);

b) Payments for provision of bulk transmission network services to asset owners as follows (and as set out in Section 7)[10]:

   1) payments made by VENCorp to SPI PowerNet for provision by SPI PowerNet of Prescribed Services. (Note that the charges levied by SPI PowerNet for these services will be subject to separate regulation by the ACCC);

   2) payments made by VENCorp to SPI PowerNet and other Transmission NSPs for bulk transmission services provided under existing contracts to VENCorp. Note that these existing contracts have been entered into by VENCorp to ensure that the reliability performance of the Victorian transmission system is maintained. The investment decisions that led to the contracts being entered into were subjected to detailed economic assessments using criteria that are consistent with those set out in the Code's Regulatory Test. The contracts are typically long-term agreements specifying pricing terms that are generally independent of the ACCC's regulatory determinations governing pricing of Prescribed Services; and

   3) the costs of payments that VENCorp will make to providers of new augmentations that will be required over the course of the five and a half year period to maintain adequate levels of transmission system reliability and performance. Each augmentation will proceed only if it meets the requirements of the Code's Regulatory Test. If the augmentation is undertaken by SPI PowerNet on a non-contestable basis, prices and terms for the service will be determined in accordance with all applicable regulatory provisions. If the augmentation is procured by VENCorp through a competitive tender process, the prices and terms for the service will be determined competitively.

[10] It should be noted that all these payments relate to prescribed transmission services as defined in the Code, even though VENCorp procures most of its services from asset owners on a contestable basis.

6 OPERATING EXPENDITURE

6.1 Overview of cost forecasts and key assumptions

Table 6.1 sets out a summary of VENCorp's budgeted operating expenditure for the period from 1 January 2003 to 30 June 2008. Values shown are in real dollars as at March 2002 and exclude GST.

Planned Cost	Forecast Financials (in 2002 $'000) for Year ending 30 June					
	2003 (6 months)	2004	2005	2006	2007	2008
Operational Expenditure	**2,715**	**5,533**	**5,668**	**6,045**	**6,087**	**6,209**
Non TUoS Revenues[11]	(23)	(148)	(150)	(152)	(153)	(154)
Net Operational Expenditure	**2,691**	**5,385**	**5,518**	**5,893**	**5,934**	**6,055**
Energy (GWh)[12]	24,395	50,062	50,995	52,003	52,835	53,628
$/MWh	0.11	0.11	0.11	0.11	0.11	0.11

Table 6.1: Summary of Operating Expenditure

These forecasts are based on a number of key assumptions including:

- No significant change to the Transmission Network Service Provider function undertaken by VENCorp; and
- No significant change to the organisational structure of VENCorp, which may impact the on the allocation of overheads to VENCorp's electricity functions.

Further details of the basis of these forecasts are provided below.

6.2 Activities to be undertaken by VENCorp over the forecast period

The budgeted operating expenditure includes all direct and indirect costs associated with the efficient delivery by VENCorp of all services relating to VENCorp's statutory electricity industry functions.[13] The forecasts incorporate a modest increase in operating costs, compared to historical levels, to reflect the impact of additional work that VENCorp expects to undertake over the coming five years, in relation to the following matters:

- Over the last 10 years, there has been a relatively low level of transmission augmentation in Victoria. This reflects the relatively high level of spare capacity that was present in the main transmission system in the early 1990s. Over the 1990s however, the balance between peak

[11] Non TUoS revenue is consulting and other income, plus interest income, less financial expenses.

[12] The energy value is on a generator sent out basis, in accordance with table 4.7 of VENCorp's 2002 Annual Planning Review. The value shown for year ending June 2003 is 50% of the full year value.

[13] The key functions are listed and described in Section 3.4 of this submission.

demand and installed transmission capacity has tightened to the point where the need is emerging for more significant transmission augmentation works to be undertaken. VENCorp is expecting to increase its in-house technical and analytical capability to effectively plan and facilitate these augmentation works.

- Similarly, the balance between demand and generating capacity has tightened in recent years. This has already led to the need for additional new generation to be connected to the main transmission system, and further new capacity will be installed over the coming five years. New generation is now typically installed in smaller increments than those seen in the past. This leads to an increase in the number of connection applications, and an increase in the volume of work associated with the technical analysis of such applications. In addition, the installation of new generation is expected to raise policy issues; for instance, issues associated with the network access rights of existing and new generators. These are complex issues, and VENCorp expects that additional resources will be required to address these issues in a timely and satisfactory manner. Although VENCorp will charge applicants a connection fee in accordance with the Code, it is not practical that all such costs, e.g. development of policies on access rights etc, be recovered from new applicants.

- VENCorp's recent experience in relation to the proposed "Southernlink" entrepreneurial interconnection proposal indicates that the technical and commercial analysis associated with such proposals is very resource-intensive. VENCorp considers it is reasonable to expect that there will be further proposals for entrepreneurial development of new and existing interconnectors, and the costs forecasts incorporate an allowance for such activities.

- The "Network and Distributed Resources" Code changes promulgated on 13 February 2002 impose new obligations on Transmission NSPs in areas such as consultation during the planning process. Whilst VENCorp is fully supportive of transparent and consultative planning processes, it also notes that the recent Code changes will have an impact on resources. Those expected impacts have been incorporated into the costs forecasts.

- The implementation, and on-going administration associated with the Code changes arising from the Transmission and Distribution Pricing Review are expected to require additional resources.

- Further review of the National Code and development of the NEM are expected over the next five years. Known development activities at the time of preparation of this submission include the NECA 'RIEMNS' review and various reviews and developments associated with Ancillary Services / NCAS market arrangements. VENCorp anticipates that its effective participation in these and other development activities over the next five years will require additional resources, and this has been incorporated into the forecasts of costs for the coming five years.

- VENCorp's role in electricity emergency management changed significantly in 2000 when the Victorian government revised the Electricity Industry Act 2000 and made VENCorp responsible for communicating with the community and industry during a period of restrictions. This required additional emergency planning groups to be established along with some organizational restructuring within VENCorp. Consequently, rather than the costs of VENCorp's Communications Department being allocated solely to VENCorp's statutory gas functions, as of 2002/03, some of the overhead costs for this function are now allocated to VENCorp's statutory electricity functions.

- Similarly, organizational restructuring has resulted in VENCorp's Risk Management and Compliance functions being re-assigned from the statutory gas part of the business to the Corporate area. As such, some costs for these functions have been allocated to VENCorp's statutory electricity functions. The re-allocation is fair and reasonable as the Compliance section co-ordinates risk management, compliance and process documentation work across the entire organisation.

- VENCorp's experience during the recently-commenced SNOVIC project has clarified the respective responsibilities of VENCorp and asset constructors for obtaining local government planning permits to construct new assets. It would appear that in most cases in the future, any significant augmentation either within existing infrastructure or on greenfield sites, will require VENCorp to obtain local government planning and building permits. This requirement will increase the workload and level of consultancies required by VENCorp.

6.3 Substantiation of cost forecasts

The cost forecasts shown in Table 6.1 are consistent with those contained in VENCorp's corporate plan, which was approved by the VENCorp Board on 22 April 2002.

As noted in Sections 2.2 and 2.5 of this submission, VENCorp's governance arrangements are unique insofar as:

- VENCorp is the only Transmission Network Service provider in Australia which is constituted as a not-for-profit organisation;

- VENCorp's corporate objectives explicitly require the organisation to deliver its services and to perform its functions, in a cost-effective manner; and

- VENCorp's Board has in place a number of processes, including internal and external scrutiny of forecast and actual cost performance, to ensure that budgeted and actual cost performance are consistent with best practice.[14]

These arrangements are aimed at providing industry stakeholders (and in particular, those stakeholders who bear the costs of VENCorp's statutory electricity functions) with an active role in scrutinising and reviewing VENCorp's budgeted and actual cost performance. In view of these considerations, all stakeholders, including the ACCC can have a good deal of comfort that the costs recovered by VENCorp through its TUoS charges reflect efficient costs. Similarly, the involvement of the VENCorp Board in scrutinising and approving the Corporate Plan (on which the forecasts in Table 6.1 are based) should provide a good deal of assurance to all stakeholders that the cost forecasts set out in this submission reflect efficient levels, having regard to the unique nature and scope of the statutory electricity functions undertaken by VENCorp.

Further details of the cost forecasts are provided in Attachment 3.

[14] For instance, VENCorp provides monthly financial reports to all stakeholders. These reports show in detail the month, year to date and full year forecasts, and are designed to keep all stakeholders informed of VENCorp's financial performance. Each month, VENCorp also publishes month and year-to-date key performance statistics compared to budget targets. A sample copy of the February 2002 business report is separately available.

6.4 Cost control and efficiency improvement initiatives within VENCorp

VENCorp is constantly seeking ways to improve the efficiency and cost-effectiveness of the organisation. Development of career plans for employees and staff-management relations are priorities for the organisation, while scrutiny of costs receives maximum focus. In light of, and in accordance with the organisation's not-for-profit and full cost-recovery status, management and internal control arrangements reflect a keen awareness that all electricity statutory costs incurred must ultimately be recovered through TUoS charges. Accordingly:

- VENCorp maintains a system of very limited expenditure delegation; and
- regardless of whether or not an approved budget provision exists for an item of expenditure, all expenditure must be justified prior to proceeding.

VENCorp's new organisation structure was implemented at the start of the 2000/01 financial year and it remains in place. VENCorp's objective was to have the optimum organisation structure in place by the start of the financial year, to enable delivery of the Corporate Plan. This objective has been achieved, and has been shown to be successful.

Following VENCorp's employee opinion survey, action plans were formulated to address issues ahead of the start of the 2000/01 financial year, and as a consequence, a number of improvements were introduced. In May 2001 VENCorp conducted a second Employee Opinion Survey. Due in many ways to significant efforts made by the organisation as a whole to address key areas in need of attention, the survey results were a major improvement compared to the results of the first survey undertaken in 2000 – in fact VENCorp's overall performance score increased by 20%.

6.5 Risk management arrangements

As an organisation with major responsibilities for managing emergencies in the electricity industry, risk management is another high priority for VENCorp.

The VENCorp Board has four committees, one of which is the Safety and Emergency Management Committee. This Committee ensures that VENCorp has the necessary programmes and processes in place to fulfil its responsibilities for safety and management of emergencies, and that VENCorp observes its statutory compliance with safety regulations.

Another Board committee is the Audit and Risk Committee, which assesses and reviews internal and external audits, and which is also responsible for assessing the adequacy of VENCorp's accounting, financial and operating controls, and risk management strategy. This Committee also recommends the appointment of the internal auditors and the scope of the audit.

During 2000/01, PriceWaterhouseCoopers assisted VENCorp to undertake a review of VENCorp's risk management strategy. A number of recommendations for improvement were made following that review, and these recommendations are in the course of being implemented.

VENCorp's Business Continuity Plan and a new Emergency Management Manual covering VENCorp's response at times of gas and electricity emergencies were finalised and put in place at the conclusion of 2000/01.

6.6 Allocation of costs between VENCorp functions

VENCorp's statutory functions include responsibilities in both gas and electricity, some of which are regulated by the ACCC, and others which are regulated by the Essential Services Commission or by other means.

In order to accurately allocate VENCorp's costs to each of these separate functions, VENCorp utilises an activity recording system called Timecontrol. Under this system, all VENCorp personnel record their hours of work on a timesheet system.

This data is used to determine the percentages for apportioning indirect costs from corporate to VENCorp's business functions (refer Table A3.12 in Attachment 3). The corporate costs of insurance, computer maintenance and licences, occupancy and corporate system depreciation are apportioned on the numbers allocated to each function respectively based on headcount and workstations.

7 NETWORK AUGMENTATION EXPENDITURE

7.1 VENCorp's Transmission Planning Processes

The transmission network provides bulk supply of energy between major generation and load centres. While the network is very reliable the consequences of any outages may be very severe both in terms of the amount of load that is lost and the duration of the interruption. Consequently the transmission network must be designed with some redundancy. Generally this requires that there is sufficient capability built in to the network to allow for the unexpected outage of any plant item under extreme conditions, without resulting in immediate overloads on other elements. The consequences of such overloads could be very severe since they may ultimately lead to cascade tripping of transmission elements and loss of system security.

In accordance with the Code, all transmission investment must satisfy the regulatory test as promulgated by the ACCC in December 1999. An investment satisfies this test if:

(a) in the event the augmentation is proposed in order to meet an objectively measurable service standard linked to the technical requirements of schedule 5.1 of the Code – the augmentation minimises the net present value of the cost of meeting those standards; or

(b) in all other cases – the augmentation maximises the net present value of the market benefit.

VENCorp's network planning is aimed at ensuring that the security of the power system can be maintained following the loss of the most critical transmission element at times of peak demand. However, VENCorp does not apply a deterministic (n-1) planning basis in considering the impact of transmission outages on supply reliability (that is, customer load shedding). Transmission investment decisions are based on a probabilistic analysis of energy at risk. That analysis includes consideration of the probability-weighted impacts on supply reliability of unlikely, high cost events such as single and multiple outages of generation or rotating reactive compensation plant, and unexpectedly high levels of demand. This approach provides a sound actuarial estimate of the expected value of energy at risk. However, implicit in its use is acceptance of the risk that there may be circumstances when the planned capability of the network will be insufficient to meet actual demand.

VENCorp's probabilistic planning and investment criteria are consistent with part (b) of the regulatory test, with all but a few minor projects being justified on the basis of expected economic costs and benefits. It is noted that in 2001, VENCorp undertook a detailed review of its network planning and investment criteria. The review involved the production of an issues paper, and subsequent consultation with a wide range of stakeholders. The review concluded that VENCorp should continue to apply a probabilistic approach to network planning and investment decision analysis. Further details of the review are provided in Section 7.1.2 below.

7.1.1 Details of VENCorp's Transmission Planning Criteria

As stated above, VENCorp's transmission planning criteria are based on an economic net benefits test consistent with part (b) of the regulatory test. In summary, the major costs and benefits associated with augmentation of the transmission network are considered over a range of plausible market development scenarios and tested against a range of network and non-network alternatives.

A probabilistic simulation model of the Victorian electricity market is presently used to derive a range of possible hourly generating dispatch scenarios for each year for a range of feasible market development scenarios which can then be used to assess the extent of transmission overloads, and the incremental dispatch costs associated with different levels of network capability. The energy which cannot be supplied is a critical parameter in justifying any network investment.

The major benefits of an augmentation considered are the avoidance of costs associated with a "no augmentation" base case, compared to options that involve the provision of varying levels of additional network and / or generation and/or demand management capability. These avoided costs include:

- the value of any load that must be curtailed to ensure that the transmission system does not operate beyond its applicable rating[15] for both unplanned and planned outages;
- the value of any load that must be shed following an outage to return the loading on the plant to its continuous rating;
- the value of any load shed as the result of unplanned events causing a loss of supply;
- changes in incremental generation costs that arise because of different levels of transmission system capability under the various scenarios being studied;
- reductions in the cost of ancillary services;
- reductions in the cost of losses; and
- impact on the costs of externalities[16].

In undertaking an economic evaluation, the costs and benefits of all plausible generation, transmission, demand side management and other options to alleviate a network constraint are evaluated on a competitively neutral basis, applying:

- a reasonable forecast of consumer demand which takes account of the variability of temperature and the impact of temperature on demand;
- a probabilistic assessment of network capability, having regard for the uncertainty associated with the availability of generation and transmission plant;
- a discount rate consistent with prevailing capital market conditions, and appropriate for the analysis of private sector investment in the electricity sector; and
- a value of energy at risk consistent with the VoLL price cap applying in the wholesale market.

Further details of VENCorp's transmission planning criteria, and a summary of the key steps involved in undertaking a transmission investment evaluation are provided in VENCorp's 2002 Annual Planning Review.

[15] Note that the applicable rating includes in short term rating as appropriate, which can be as short as a five minute rating. The short term rating of transmission equipment is the level it can be operated at such that, following the contingency that results in the worst loading on the element, the equipment will not reach its maximum operating temperature for the applicable time (e.g. five minutes), and there will be no permanent damage or unreasonable loss of life expectancy. This enables sufficient time for action to bring the loading back to the continuous rating.

[16] In accordance with the regulatory test, only those costs of complying with existing and anticipated laws, such as those dealing with health and safety, land management, and environmental pollution are considered.

7.1.2 VENCorp's review of its transmission planning criteria

In 2001, VENCorp undertook a major review of its transmission network planning criteria, releasing a consultation paper on 6 March 2001[17]. The review was a very important process as the planning criteria applied by VENCorp are a key determinant of the reliability and standard of services (and the associated costs of the services) provided to users of the Victorian shared transmission network.

The consultation sought submissions on VENCorp's probabilistic approach to network planning, under which transmission augmentation proceeds only when the total expected (probability-weighted) cost of not proceeding exceeds the cost of the investment required to remove those costs. This approach provides a sound actuarial estimate of the expected net benefits of network augmentation. However, implicit in its use is acceptance of the risk that there may be circumstances when the planned capability of the network will be insufficient to meet actual demand, even with all network elements in service.

Ten written submissions on the Consultation Paper were received. In addition, VENCorp met with the Regulator-General's Consumer Consultative Committee to discuss transmission planning criteria. On 28 May 2001, VENCorp published on its web site a paper setting out its preliminary responses to submissions, and on 14 June, VENCorp published notes of the meeting held with the Consumer Consultative Committee.

On 25 June 2001, the VENCorp Board considered all of the submissions made by stakeholders during the consultation process. The Board subsequently approved electricity transmission network planning criteria, which are substantially the same as the existing criteria with a number of improvements.

The planning criteria and investment decision analysis methods approved by the VENCorp Board are set in Attachment 5. It is noted that these are consistent with the requirements of the Code's regulatory test.

7.2 Load Forecasts

Long-term electricity load forecasts are a key element of future electricity transmission adequacy assessment. VENCorp engaged the National Institute of Economic and Industry Research (NIEIR) to produce Victorian load forecasts to year 2015/16. These forecasts are to be published in VENCorp's Electricity Annual Planning Review 2002 and are also provided to NEMMCO under Clause 5.6.4 of the National Electricity Code for inclusion in the Statement of Opportunities. The load forecasts include annual energy consumption and half hour average Maximum Demand (MD) for summer and winter each year.

Ten year maximum demand forecasts are also provided by the Distribution Businesses for each of their points of connection with the transmission network. The Distribution Businesses forecasts provide a spatial distribution of the overall system forecasts for detailed network analysis.

[17] The planning criteria consultation paper and related documentation is available on VENCorp's website at http://www.vencorp.com.au/html/corp_consultation_docs_clsd.htm#Electricity Transmission Network and http://www.vencorp.com.au/html/elec_planning.htm#Conclusion of Consultation Process on Electricity.

7.2.1 Victorian Energy Forecasts

NIEIR has developed an integrated econometric forecast system capable of generating short to long term economic and energy forecasts at the National, State and Regional level. The key inputs to the Victorian energy forecast models include:

- Gross State Product (GSP);
- State industry growth projections;
- population, dwelling stock and customer numbers;
- real household disposable income;
- real energy prices;
- weather conditions; and
- major new industrial, mining and commercial developments.

Three scenarios of annual energy forecasts are provided corresponding to the Medium (Base), High and Low economic outlooks for Victoria. The econometric forecasts are further refined to include the impact of other factors such as greenhouse gas policies, improved appliance efficiencies and future technological developments.

Energy forecasts are broken down by major market sector namely Residential, Commercial, Industrial, Traction and Public Lighting.

Forecast residential energy usage is determined by the forecast number of households connected to the supply grid and forecast average consumption per connected household.

Forecast Commercial and Industrial loads are closely linked to industry growth projections. It should be noted that the aluminium sector and other energy intensive industrial activities are explicitly identified outside the general econometric core of the model and incorporated into the forecasts by adding these demands in as identifiable items. Other major industrial/mining projects are individually identified with explicit timing and load growth forecasts provided for each of the three load growth scenarios.

The forecast energy growth to 2011/12 for the 3 economic scenarios is shown in the Figure 7.1 below. Forecast load grows at an average annual rate of 1.95%, 2.77% and 1.12% under the Medium, High and Low economic scenario respectively.

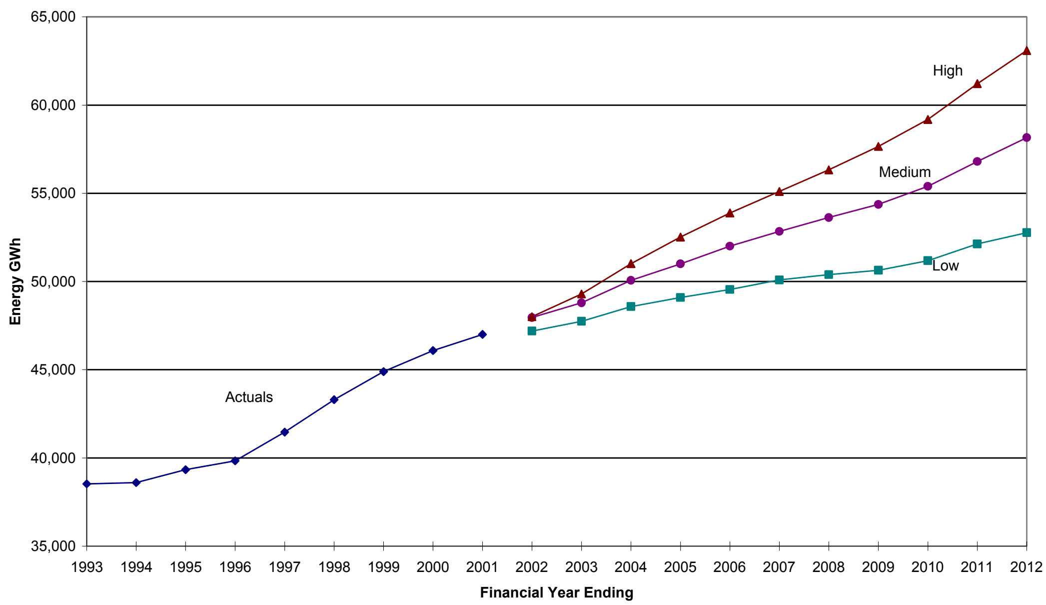

Figure 7.1 Victorian Energy forecasts

7.2.2 *Summer MD Forecasts*

Forecast Victorian summer and winter MDs are produced for 10th, 50th and 90th[18] temperature percentiles for each economic scenario. The MD forecast approach distinguishes between temperature sensitive load, non-temperature sensitive load and major industrial load.

For the summer MD, temperature sensitive load consists of space cooling appliances. Victorian summer MD has increased significantly over recent years as a result of strong economic growth, accelerated building activities and increased penetration of space cooling equipments due to hot summer temperatures experienced in recent times. A new method has been developed to forecast the temperature sensitive component of summer MD. An econometric model is developed to forecast future space cooling unit sales for 3 different economic growth scenarios combined with 3 different summer average weather conditions (ie 10th, 50th and 90th summer temperature percentiles). Average cooling appliance consumption for 10th, 50th and 90th average summer temperature percentiles is estimated from historical appliance sales, updated annually, and growth in summer MD over the recent years. The results of the above analyses are used to generate 27 sets of future summer MD cooling consumption (3 economic scenarios * 3 summer average temperature scenarios * 3 summer MD daily average temperature scenarios). Forecast summer MDs for 50% summer average temperature and 10% summer MD daily average temperature are shown in the chart below for 3 economic growth scenarios. Summer 10% MD to 2011/12 is projected to grow at 2.8%, 3.6% and 1.7% for the Medium, High and Low economic scenario respectively.

[18] The 10th, 50th and 90th temperature percentiles for summer MDs are defined as Melbourne daily average temperature in summer equal to 32.8°C, 29.4°C and 27.1°C respectively. The 10th, 50th and 90th temperature percentiles for winter MDs are defined as Melbourne daily average temperature in winter equal to 4.8°C, 6.0°C and 7.2°C respectively.

7.2.3 *Winter MD Forecasts*

For the winter MD, temperature sensitive load consists of reverse cycle air conditioners and other heating appliances. The Victorian winter MD has increased significantly over the last few years despite mild winter weather conditions. The increase in peak winter demand is believed to correlate with increased penetration of reverse cycle air conditions and convection/panel heaters in city apartments. A similar forecast approach is developed to project reverse cycle air conditioner sales to be used to forecast future growth in winter MD. Forecast winter 10% MDs grow at 2.1%, 3.0% and 1.1% per annum over the period 2002-2012 under the Medium, High and Low economic scenarios respectively.

The summer and winter MD forecasts are displayed in Figure 7.2 below.

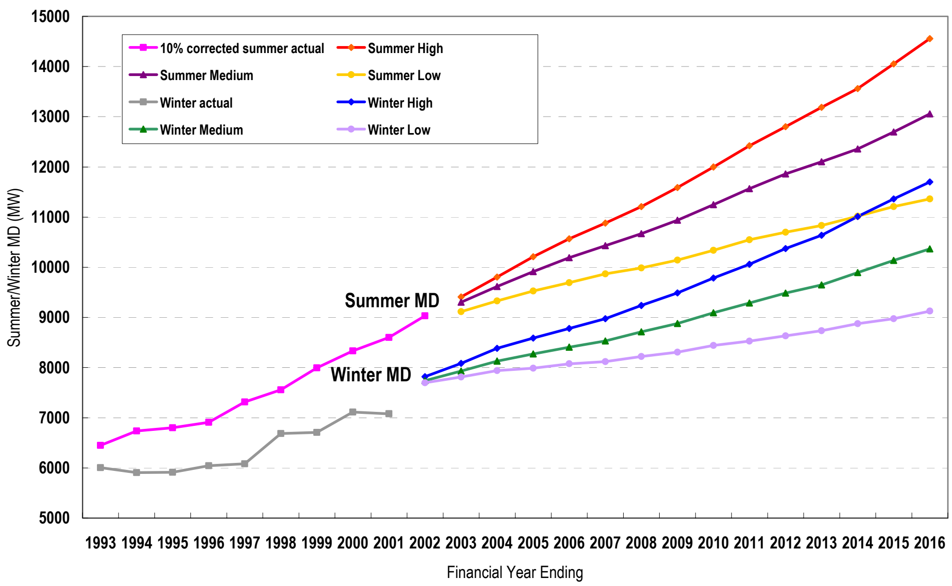

Figure 7.2 Forecast Summer and Winter MDs

7.3 Network Augmentation Expenditure

The following sections outline the projects and services, both committed and planned, that give rise to a requirement for VENCorp to make payments to asset owners for provision of bulk transmission network services.

7.3.1 SPI PowerNet Prescribed Services

VENCorp makes payments to SPI PowerNet for provision by SPI PowerNet of prescribed services, relating to the shared transmission network[19] under a Network Agreement[20]. These are the services provided by SPI PowerNet which are subject to separate regulation by the ACCC[21].

7.3.2 Committed and In service projects (other than SPI PowerNet prescribed)

This category covers payments made by VENCorp to SPI PowerNet and other Transmission NSPs for bulk transmission services provided under existing contracts to VENCorp. Note that these existing contracts have been entered into by VENCorp to ensure that the reliability performance of the Victorian transmission system is maintained. The investment decisions that led to the contracts being entered into were subjected to detailed economic assessments using criteria that are consistent with those set out in the Code's Regulatory Test. The contracts are typically long-term agreements specifying pricing terms that are generally independent of the ACCC's regulatory determinations governing pricing of Prescribed Services.

The projects in this category are summarised in Table 7.1 below[22].

VENCorp also has a number of contracts which are planned to be rolled into SPI PowerNet's regulated asset base from 1 January 2003, and therefore included in SPI PowerNet's prescribed services charge to VENCorp. VENCorp has therefore not made separate provision for these contract payments in this submission. However, in the event that these are not rolled into SPI PowerNet's regulated asset base, VENCorp will be required to make separate payments to SPI PowerNet pursuant to existing agreements.

The projects in this category are summarised in Table 7.2 below.

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[19] Note that charges for connections services are paid to SPI PowerNet directly from transmission customers such as distribution businesses and generators.

[20] This Network Agreement between SPI PowerNet and VENCorp is presently under review to better define services and include an enhanced availability incentive scheme.

[21] Refer SPI PowerNet's Revenue Cap Application for the period 1 January 2003 to 31 March 2008.

[22] It should be noted that VENCorp from time to time enters into other contracts with Network Service Providers for services requested and funded entirely by transmission customers. Such projects are not listed in this submission as VENCorp is not seeking revenue recovery via TUOS charges for such projects.

Service	Service Provider	Procurement Method
South Morang Series Capacitors	SPI PowerNet	Contestable Tender[23]
Rowville Transformer – 500/220kV 1000MVA	Rowville Transmission Facility	Contestable Tender
Reactive Support service for the period 2001/02 - 03/04	SPI PowerNet	Contestable Tender
SNOVIC 400 MW Interconnection upgrade	ABB/SPI PowerNet	Contestable Tender (Part works only)
500kV lines protection upgrades	SPI PowerNet	Non-contestable
Minor Works including: • Contingency Load Shedding at ROTS, HTS & SVTS • Manual Load Shedding at ERTS, HTS & SVTS • ATS, BLTS, KTS Autoreclose • Uprating RTS - BTS Cable • Protection Upgrade on TTS No 3 & 4 Buses	SPI PowerNet	Non-contestable

Table 7.1 Summary of Committed and In Service Projects

Service	Service Provider	Procurement Method
Victorian Network Switching Centre	SPI PowerNet	Non-contestable
Battery Duplication	SPI PowerNet	Non-contestable
Rowville Transformer Interface Services	SPI PowerNet	Non-contestable
Shunt Capacitors for 2000/2001	SPI PowerNet	Non-contestable

Table 7.2 Summary of Committed and In Service Projects that are planned to be rolled into SPI PowerNet's asset base from 1 January 2003

Further details on the major projects in this category are provided in Attachment 6.

7.3.3 Planned augmentations

This Section describes the augmentation services that VENCorp has identified as necessary to maintain network adequacy during the course of the regulatory period[24]. These will result in payments to providers of new augmentations that will maintain adequate levels of transmission system reliability and performance. Each augmentation will proceed only if it meets the requirements of the Code's Regulatory Test. If the augmentation is undertaken by SPI PowerNet on a non-contestable basis, prices and terms for the service will be determined in accordance with all applicable regulatory provisions. If the augmentation is procured by VENCorp through a competitive tender process, the prices and terms for the service will be determined competitively.

[23] Note that all contestably sourced projects include a non-contestable interface service provided by SPI PowerNet.

[24] Note that VENCorp does not plan for connection assets in Victoria, nor is it responsible for asset replacement.

Importantly, the plan is based on a number of assumptions, any one of which could alter this plan significantly. The major factors that influence the need for new augmentations are as follows:

- Location of new loads, generators, market network service providers or interconnectors;
- Load growth forecasts, including impact of embedded generation and demand side management;
- The form of the regulatory test as promulgated by the ACCC, including its major inputs such as the value of customer reliability or VoLL;
- TNSP service standard requirements; and
- Technical standards as outlined in the Code (refer schedule 5.1 of the Code);

A summary of the planned augmentations, based on four different generation development scenarios, is shown in Table 7.3 below. This is based on VENCorp's 2002 Annual Planning Review issued in 30 April 2002[25], which contains details of all the proposed projects. A description of the major projects is shown in Attachment 6 of this submission.

The scenarios shown in this Table 7.3 are based on those outlined in VENCorp's 2002 Annual Planning Review covering a ten year planning horizon. These scenarios were not selected as the only possible market development scenarios as these are limitless. However, these scenarios are market development extremes which provide for an expected upper and lower bound of transmission augmentations. The projects included in this table only represent the projects estimated to be commissioned within the regulatory period of this submission, i.e. to 30 June 2008.

[25] VENCorp's 2002 Annual Planning Review is available at VENCorp's website at www.vencorp.com.au

Scenario 1	Scenario 2	Scenario 3	Scenario 4
LV Gen up 1900 MW Import from NSW up 0 MW Metro Gen/DSM up 600 MW	LV Gen up 500 MW Import from NSW up 1400 MW Metro Gen/DSM up 600 MW	LV Gen up 1300 MW Import from NSW up 0 MW Metro Gen/DSM up 1200 MW	LV Gen up 0 MW Import from NSW up 1400 MW Metro Gen/DSM up 1100 MW

Common Projects across all scenarios

Augmentation	Estimated Capital Cost by scenario ($M)				Estimated Timing by scenario (December:)			
	1	2	3	4	1	2	3	4
4th 500 kV line project and associated 1000 MVA transformer at Cranbourne or Rowville	36	36	36	36	2003	2003	2003	2003
4th Dederang 330/220 kV transformer and Mt Beauty 220 kV switchgear replacement	12	12	12	12	2005	2004	2004	2004
Moorabool 1000 MVA 500/220 kV transformer spare phase	4	4	4	4	2004	2004	2004	2004
Fault Level Mitigation	10	13	15	15	From 2004	From 2004	From 2004	From 2004
Reactive Support	30	25	20	18	From 2003	From 2003	From 2003	From 2003
Upgrade Rowville – Springvale – Heatherton 220kV lines	2	2	2	2	2004	2004	2004	2004
Upgrade Ringwood 220kV supply	4	4	4	4	2003	2003	2003	2003
Miscellaneous Works[26]	15	15	15	15	From 2003	From 2003	From 2003	From 2003
Metropolitan 1000MVA 500/220kV transformer[27]	30	51	30	51	2005	2006	2007	2006
Total	**143**	**162**	**138**	**157**				

Table 7.3 (a) Summary of Planned Augmentations – common projects

[26] This category represents provision for unidentified works that are generally less than $1M. For example, protection, control and termination equipment upgrades and other works required to maintain the reliability of the transmission network. As with other projects, works in this category will only proceed if justified in accordance with the Regulatory Test.

[27] For scenarios 1 and 3, this involves a metropolitan 500/220kV 1000 MVA transformer. For scenarios 2 and 4, this involves a 500/330kV and a 330/220kV transformer at South Morang, including South Morang switching and line works.

Scenario Specific Projects							
Scenario 1		Scenario 2		Scenario 3		Scenario 4	
Augmentation	**$M**	**Augmentation**	**$M**	**Augmentation**	**$M**	**Augmentation**	**$M**
Rowville – Richmond 220kV lines upgrade (Dec 2007)	4	Interconnection Upgrade comprising (approx Dec 2006):		Rowville – Richmond 220kV lines upgrade (Dec 2007)	4	Interconnection Upgrade comprising (approx Dec 2006):	
		• Construct a 3rd SMTS-DDTS 330 kV line, including series compensation	97			• Construct a 3rd SMTS-DDTS 330 kV line, including series compensation	97
		• New 330 kV line from DDTS-JIND with series compensation	24			• New 330 kV line from DDTS-JIND-WAGGA with series compensation	24
		• Series compensation of the EPS-TTS 220 kV (SMTS) line	5			• Series compensation of the EPS-TTS 220 kV (SMTS) line	5
		• 150 MVAr caps at DTTS or WOTS	4			• 150 MVAr caps at DTTS or WOTS	4
		• Upgrade of existing DDTS-SMTS 330 kV lines to 82 degrees and associated series capacitor works	4			• Upgrade of existing DDTS-SMTS 330 kV lines to 82 degrees and associated series capacitor works	4
Sub-Total (Scenario Specific Projects)	**4**		**134**		**4**		**134**
Total (By Scenario)	**147**		**296**		**142**		**291**

Table 7.3 (b) Summary of Planned Augmentations – scenario specific

7.4 Annual Augmentation Charges

The network augmentation services outlined in Section 7.3 are paid for as annual charges to service providers. This section summarises these annual charges. All values are provided as real dollars as at March 2002, and will be subject to CPI escalations in accordance with the applicable contracts, and GST payments.

7.4.1 SPI PowerNet Prescribed Services

Payment for these services will be as approved by the ACCC.

7.4.2 Committed and In service projects (other than SPI PowerNet prescribed)

Table 7.4 below shows the total expenditure in this category, as individual projects in this category were sourced through confidential tender. A separate confidential table detailing the costs for each project will be provided to the ACCC.

Committed or In Service Projects (excluding SPI Prescribed charges)
Expected Annual Charges (real dollars as at March 2002)

Committed Projects	Financial Year (1 July to 30 June)					
	2002/03 (6 months)	2003/04	2004/05	2005/06	2006/07	2007/08
	($M)	($M)	($M)	($M)	($M)	($M)
South Morang Series Capacitors Rowville Transformer (contestable portion only) Capacitor Banks 2001/02 – 2003/04 SNOVIC (Victorian works only) 500kV protection upgrades Minor Works	5.9	10.9	10.6	10.2	9.7	9.5

Table 7.4 Annual Charges for Committed or In Service Projects

7.4.3 Planned augmentations

Forecast annual network charges relating to the forecast capital expenditure are based on the following assumptions:

a) A real pre-tax WACC of 7.1% is applied, and is derived from:

- the real post tax WACC of 6.9% (as per page iii of Appendix F of SPI PowerNet's revenue cap submission to the ACCC; plus
- an allowance of 0.2% (20 basis points) being the approximate annual value of the proposed net tax allowance (set out in Table 8.3 on page 65 of SPI PowerNet's revenue cap submission, expressed as a proportion of the Regulated Asset Base value.

b) an allowance for annual operations and maintenance costs of 1.7% per year in real terms, of the undepreciated capital cost of the asset (although this value will in practice vary significantly from project to project depending on the works involved and incremental allocation of overheads in relation to SPI PowerNet non-contestable works; and

c) a straight line current cost depreciation charge;

It is noted that the ACCC will be making a determination in relation to SPI PowerNet's allowed rate of return (WACC) and the level of operations and maintenance costs that SPI PowerNet will be permitted to recover through its regulated charges. The ACCC's determination may result in values and outcomes that differ from those assumed by VENCorp in this submission for the purpose of estimating the annual charges for the forecast network augmentations. The forecast annual charges are therefore subject to variation. In addition, where VENCorp seeks augmentations under competitive tender conditions, the resulting annual charges may vary from those assumed in this submission. For these reasons, VENCorp's forecasts of annual charges for network augmentations are subject to change.

Tables 7.5 to 7.8 below show the expected annual network charges under each of the four scenarios.

Scenario 1
Expected Annual Charges (real dollars as March 2002)

Uncommitted Projects	Financial Year (1 July to 30 June)					
	2002/03 (6 months)	2003/04	2004/05	2005/06	2006/07	2007/08
	($M)	($M)	($M)	($M)	($M)	($M)
4th 500 kV line project and associated 1000 MVA transformer at Cranbourne or Rowville	0.0	2.5	4.3	4.2	4.1	4.1
4th Dederang 330/220 kV transformer and Mt Beauty 220 kV switchgear replacement	0.0	0.0	0.0	0.8	1.4	1.4
2nd Moorabool 1000 MVA 500/220 kV transformer – spare phase	0.0	0.0	0.3	0.5	0.5	0.5
Fault Level Mitigation	0.0	0.0	0.2	0.5	0.9	1.2
Reactive Support	0.0	0.5	1.3	2.1	2.9	3.6
Upgrade Rowville – Springvale – Heatherton 220kV lines	0.0	0.0	0.2	0.3	0.3	0.3
Upgrade Ringwood 220kV supply	0.0	0.3	0.5	0.5	0.5	0.5
Miscellaneous Works	0.2	0.2	0.6	1.0	1.4	1.8
Metropolitan 1000MVA 500/220kV transformer	0.0	0.0	0.0	2.1	3.6	3.5
Rowville – Richmond 220kV lines upgrade	0.0	0.0	0.0	0.0	0.0	0.3
Total (Scenario 1)	**0.2**	**3.6**	**7.5**	**12.2**	**15.6**	**17.2**

Table 7.5

Scenario 2
Expected Annual Charges (real dollars as at March 2002)

Uncommitted Projects	**Financial Year (1 July to 30 June)**					
	2002/03 (6 months)	**2003/04**	**2004/05**	**2005/06**	**2006/07**	**2007/08**
	($M)	**($M)**	**($M)**	**($M)**	**($M)**	**($M)**
4th 500 kV line project and associated 1000 MVA transformer at Cranbourne or Rowville	0.0	2.5	4.3	4.2	4.1	4.1
4th Dederang 330/220 kV transformer and Mt Beauty 220 kV switchgear replacement	0.0	0.0	0.8	1.4	1.4	1.4
2nd Moorabool 1000 MVA 500/220 kV transformer – spare phase	0.0	0.0	0.3	0.5	0.5	0.5
Fault Level Mitigation	0.0	0.0	0.3	0.7	1.1	1.6
Reactive Support	0.0	0.4	1.1	1.7	2.4	3.0
Upgrade Rowville – Springvale – Heatherton 220kV lines	0.0	0.0	0.2	0.3	0.3	0.3
Upgrade Ringwood 220kV supply	0.0	0.3	0.5	0.5	0.5	0.5
Miscellaneous Works	0.2	0.2	0.6	1.0	1.4	1.8
Metropolitan 1000MVA 500/220kV transformer	0.0	0.0	0.0	0.0	3.6	6.1
Interconnection Upgrade	0.0	0.0	0.0	0.0	10.0	16.9
Total (Scenario 2)	**0.2**	**3.5**	**8.1**	**10.4**	**25.4**	**36.1**

Table 7.6

Scenario 3
Expected Annual Charges (real dollars as March 2002)

Uncommitted Projects	Financial Year (1 July to 30 June)					
	2002/03 (6 months)	2003/04	2004/05	2005/06	2006/07	2007/08
	($M)	($M)	($M)	($M)	($M)	($M)
4th 500 kV line project and associated 1000 MVA transformer at Cranbourne or Rowville	0.0	2.5	4.3	4.2	4.1	4.1
4th Dederang 330/220 kV transformer and Mt Beauty 220 kV switchgear replacement	0.0	0.0	0.8	1.4	1.4	1.4
2nd Moorabool 1000 MVA 500/220 kV transformer – spare phase	0.0	0.0	0.3	0.5	0.5	0.5
Fault Level Mitigation	0.0	0.0	0.3	0.8	1.3	1.8
Reactive Support	0.0	0.3	0.9	1.4	1.9	2.4
Upgrade Rowville – Springvale – Heatherton 220kV lines	0.0	0.0	0.2	0.3	0.3	0.3
Upgrade Ringwood 220kV supply	0.0	0.3	0.5	0.5	0.5	0.5
Miscellaneous Works	0.2	0.2	0.6	1.0	1.4	1.8
Metropolitan 1000MVA 500/220kV transformer	0.0	0.0	0.0	0.0	0.0	2.1
Rowville – Richmond 220kV lines upgrade	0.0	0.0	0.0	0.0	0.0	0.3
Total (Scenario 3)	**0.2**	**3.4**	**8.0**	**10.2**	**11.5**	**15.1**

Table 7.7

Scenario 4
Expected Annual Charges (real dollars as March 2002)

Uncommitted Projects	Financial Year (1 July to 30 June)					
	2002/03 (6 months)	2003/04	2004/05	2005/06	2006/07	2007/08
	($M)	($M)	($M)	($M)	($M)	($M)
4th 500 kV line project and associated 1000 MVA transformer at Cranbourne or Rowville	0.0	2.5	4.3	4.2	4.1	4.1
4th Dederang 330/220 kV transformer and Mt Beauty 220 kV switchgear replacement	0.0	0.0	0.8	1.4	1.4	1.4
2nd Moorabool 1000 MVA 500/220 kV transformer – spare phase	0.0	0.0	0.3	0.5	0.5	0.5
Fault Level Mitigation	0.0	0.0	0.3	0.8	1.3	1.8
Reactive Support	0.0	0.3	0.8	1.3	1.7	2.2
Upgrade Rowville – Springvale – Heatherton 220kV lines	0.0	0.0	0.2	0.3	0.3	0.3
Upgrade Ringwood 220kV supply	0.0	0.3	0.5	0.5	0.5	0.5
Miscellaneous Works	0.2	0.2	0.6	1.0	1.4	1.8
Metropolitan 1000MVA 500/220kV transformer	0.0	0.0	0.0	0.0	3.6	6.1
Interconnection Upgrade	0.0	0.0	0.0	0.0	10.0	16.9
Total (Scenario 4)	**0.2**	**3.4**	**7.9**	**10.1**	**24.9**	**35.5**

Table 7.8

7.4.4 Summary of Planned Network Expenditure

It is emphasised that there is a degree of uncertainty as to whether the actual development of the Victorian shared transmission network over the period to June 2008 will be in accordance with any of the four scenarios outlined above. It is considered that there is a higher level of uncertainty associated with Scenarios 2 and 4 because these scenarios involve interconnection works that may be built by other parties (either on a regulated or entrepreneurial basis). In addition, these scenarios involve a higher proportion of expenditure occurring later in the regulatory period, and consequently there is a higher level of uncertainty that today's estimates of that expenditure will accurately reflect the actual costs incurred in the future. Given these considerations, VENCorp's estimate of augmentation costs over the 2003 to 2008 regulatory period does not incorporate these higher-cost Scenarios.

However, if these (or any other) higher-cost developments are found to satisfy the Regulatory Test and they subsequently proceed, then VENCorp will make an application to the ACCC to pass through the additional costs during the forthcoming regulatory period. It is emphasised that pass-through of additional unforeseen augmentation costs (subject to the regulatory test being met) is a fundamental feature of the regulatory arrangements that presently apply to VENCorp. As noted in Section 8 below, VENCorp's cost estimates for the 2003 to 2008 regulatory period and its capital structure over that period contain no provision for the costs associated with variations between VENCorp's actual costs and its allowed revenue. The full pass-through of all costs of augmentations that meet the requirements of the Regulatory Test is therefore required to ensure that the key features of the Victorian regulatory arrangements are maintained (in accordance wither the requirements of clause 9.8.4(a)(2) of the National Electricity Code).

Therefore, for the purposes of providing an estimated annual augmentation expenditure, VENCorp has selected the annual charges estimated to arise from scenario 1, as shown in Table 7.9 below.

It should be stressed that the projects that make up this expenditure plan will only proceed if justified in accordance with the Regulatory Test.

Financial Year (1 July to 30 June)					
2002/03 (6 months)	**2003/04**	**2004/05**	**2005/06**	**2006/07**	**2007/08**
($M)	**($M)**	**($M)**	**($M)**	**($M)**	**($M)**
0.2	3.6	7.5	12.2	15.6	17.2

Table 7.9 Summary of Estimated Future Annual Augmentation Expenditure

8 OVERALL REVENUE REQUIREMENT AND ASSOCIATED REVENUE CONTROL ARRANGEMENTS

Table 8.1 below provides a summary of the main components of VENCorp's estimated total revenue requirement for the period ending 30 June 2008. The values are in real dollars as at March 2002 and exclude GST.

Overall Revenue Requirement	Forecast Financials (in 2002 $M) for Year ending 30 June					
	2003 (6 months)	2004	2005	2006	2007	2008
Net Operational Expenditure	2.7	5.4	5.5	5.9	5.9	6.1
Committed Annual Augmentation charges	5.9	10.9	10.6	10.2	9.7	9.5
Planned Annual Augmentation charges	0.2	3.6	7.5	12.2	15.6	17.2
Total VENCorp forecast expenditure	**8.8**	**19.9**	**23.6**	**28.3**	**31.2**	**32.8**
SPI PowerNet Prescribed Service charges[28]	122.1	238.4	237.5	234.8	232.9	231.7
Total costs to be recovered through TUoS charges by VENCorp	**130.9**	**258.3**	**261.1**	**263.1**	**264.1**	**264.4**
Energy (GWh)[29]	24,395	50,062	50,995	52,003	52,835	53,628
Victorian TUOS charges ($/MWh)	5.4	5.2	5.1	5.1	5.0	4.9

Table 8.1: Main components of VENCorp's estimated total revenue requirement for the period ending 30 June 2008

As noted in Section 3 of this submission, it is considered that some of the principles set out in Part B of Chapter 6 of the Code are not readily applicable to VENCorp, given the organisation's not-for-profit status, and its associated governance arrangements. As a consequence, it is considered that it would be inappropriate and impracticable for a "CPI minus X" revenue cap to be applied to the total cost that VENCorp must recover through TUoS charges. For instance:

- The forecast of future augmentation costs is based partly on assumptions about the prices that may be tendered by competing network owners to construct, finance and manage the required augmentations. These assumptions may, in effect be "locked in" through the imposition of a revenue cap on VENCorp's total TUoS revenue requirement. Such arrangements would leave VENCorp exposed to the risk that actual tendered prices vary from those assumed. These arrangements would not be compatible with VENCorp's "not-for-profit" status. Similarly, while such arrangements may be argued to provide commercial (and asset-owning) NSPs with incentives to minimise augmentation costs, such arrangements are not consistent with VENCorp's status as having commercially incentives to invest. As noted in Section 3 of this

28 SPI PowerNet's estimated prescribed services charge to VENCorp is based on SPI PowerNet's revenue cap application to the ACCC, an allocation to VENCorp of 86% of total charges, a reduction based on expected availability incentive payments, and an annual CPI estimate of 3.1% as used by SPI PowerNet to express as real 2002 dollars.

29 The energy value is on a generator sent out basis. The value shown for year ending June 2003 is 50% of the full year value.

submission, VENCorp's governance arrangements provide the necessary mechanisms and internal controls to ensure that investment decisions are efficient, and that augmentations are constructed in a cost-effective manner.

- VENCorp is required under its Transmission Licence to competitively source new investment. This, in turn, provides a means of introducing competition into the design, construction, maintenance, financing and long-term ownership of transmission infrastructure, leading to reduced costs. The introduction of competition ensures that once an investment decision is made, it will be implemented as efficiently as possible. It is VENCorp's experience that this particular feature of the arrangements provides a very effective means of ensuring cost-effective execution of capital works. VENCorp considers this approach to deliver outcomes that are superior to those likely to be delivered by the alternative model, which involves regulation of commercially oriented transmission NSPs (that make investment decisions, construct and own the associated assets, and derive a regulated income stream from those assets).

- The actual timing of augmentations may vary from that assumed in the forecasts set out in Table 8.1 above, as a result of load forecasting errors, for instance. Under present Victorian regulatory arrangements, any such variations (that may result either in deferral or advancement of augmentation projects) are refected in annual TUoS charges. The imposition of a total revenue cap would leave VENCorp bearing the risk (and associated costs or benefits) associated with variations between the forecast and actual program of augmentations. Such arrangements would not be compatible with VENCorp's not-for-profit status.

- VENCorp's capital structure and cost forecasts contain no provisions for the costs associated with bearing and managing the risks it would face under a CPI minus X revenue cap. The operating cost forecasts contain no provisions that would provide a "buffer" for unforeseen changes. Moreover, VENCorp has no capital base to absorb the revenue fluctuations that would be present under a revenue cap regime where differences are likely to arise between the forecast and actual costs of augmentation over a regulatory period. In accordance with its "not-for-profit" status, VENCorp recovers no "return on capital".

For these reasons, and for the reasons set out in detail in Section 3 of this submission, it is considered that any revenue control arrangements applied to VENCorp should be consistent with the existing Victorian regulatory arrangements, and should contain mechanisms that enable the following outcomes to be achieved:

a) In relation to ***operational expenditure***, VENCorp:

   i) will recover on an annual basis (through TUOS charges) its actual operational expenditure on a full cost recovery basis subject to the constraints listed in paragraphs (ii) to (v) below;

   ii) will be subject to an aggregate operational expenditure cap over the five and a half year regulatory period commencing on 1 January 2003 of $31.5M in real dollars as at March 2002, in accordance with Table 8.1 above;

   iii) will budget to ensure that its annual net operational expenditure does not exceed the forecast shown in Table 8.1 above;

iv) may, in any one year, recover in excess of the annual operational expenditures listed in Table 8.1 above, subject to maintaining an aggregate operational expenditure cap over the five and a half year period as per paragraph (ii) above; and

v) will, in the event that operational expenditure is forecast to exceed the aggregate operational expenditure cap, make an application to the ACCC for any additional costs it seeks to recover through TUOS charges.

b) In relation to ***augmentation expenditure***:

i) Costs associated with any augmentation work that exceeds the forecasts of costs set out in this submission should be permitted to be recovered, subject to the requirement that any such augmentation is justified under the Regulatory Test. This is of particular importance as the market development scenario selected as the basis for the future augmentation costs in this application results in the lowest overall augmentation costs; and

ii) Based on paragraph (i), VENCorp will recover on an annual basis (through TUOS charges) its actual augmentation expenditure on a full cost recovery basis.

c) In relation to ***overall expenditure***:

i) Adjustments for the impact of CPI on all budgeted costs should be provided;

ii) Subject to the constraints on operational expenditure outlined in paragraphs (a)(i) to (a)(v) above, costs that are over or under recovered in previous years should be carried forward from year to year, to ensure that VENCorp's not-for-profit status is maintained;

iii) To allow for effective transition from the current regulatory arrangements pursuant to the Victorian Electricity Supply Tariff Order, any over or under recovery in costs incurred in the 2002/03 financial year, should be carried forward as an adjustment to the overall revenue requirement in 2003/04;

iv) There should be effective provisions to allow for adjustment to VENCorp's total revenue requirement, to reflect any changes to the National Electricity Code or other relevant instruments, which impact on VENCorp's costs. Such changes include, but are not limited to, the following:

- inter-regional TUoS revenue paid or received by VENCorp;
- any fees imposed by NEMMCO;
- VENCorp should have an ability to fully pass through the costs of any additional costs that may arise as a result of implementing the recommendations of the MSORC review;
- VENCorp should have an ability to fully pass through the costs that may arise with any future changes to the treatment of ancillary services in the NEM; and

- Changes in costs associated with any changes to service standards, changes to the requirements of the regulatory test (and any other associated planning and investment decision criterion including the value of VoLL or value of customer reliability), or amendment of Schedule 5.1 of the Code should be fully incorporated into VENCorp's TUoS charges.

v) There should be effective provisions to allow for adjustment to VENCorp's operational revenue requirement, to reflect any material changes to the augmentation program outlined in this submission;

vi) There should be effective provisions to allow for adjustment to VENCorp's total revenue requirement, to reflect any differences between the key assumptions outlined in Section 6 and actual outcomes; and

vii) VENCorp has assumed that no optimisation will be applied to the committed augmentation services, and reserves the right to resubmit this application in the event that the ACCC intends to apply optimisation.

9 SERVICE STANDARDS

VENCorp recognises that a fundamental requirement of sound economic regulation is the linking of regulated prices (or revenues) to defined standards of service. To this end, it is noted that VENCorp presently has in place a number of network agreements with network owners for the provision of network services. Those agreements define the level of service to be provided to VENCorp, and in most cases include performance incentives in the form of availability incentive schemes. In some cases, the charge payable by VENCorp for that service is also fixed in the agreement.[30] The forecasts of costs set out in this submission reflect assumptions that:

- the service standards defined under each network agreement that VENCorp has already entered into will be maintained in the future; and
- the service standards associated with forecast new augmentations over the regulatory period will be consistent with existing standards.

It is noted that the ACCC is presently reviewing the issue of transmission network service standards. VENCorp welcomes this initiative, and has been a participant in the ACCC's review process. It is noted that the implementation of any changes to existing service standards (as a result of the ACCC's review) may give rise to a change in the cost to VENCorp of procuring network services. As stated in Section 8 above, it will be important for the ACCC's consideration of revenue controls to take full account of the impact on costs of any change in network service standards.

VENCorp effectively acts an intermediary in the transmission network service market.[31] Consequently, VENCorp's ability to offer improved levels of network service will reflect its ability to procure corresponding improvements in the level of network service provided to it by network owners such as SPI PowerNet. Important corollaries of this are that:

- the ACCC's review of network service standards must encompass consideration of the service standards delivered to VENCorp by network owners, as well as the standard of service delivered by VENCorp to network users; and
- there must be consistency between the service standards that VENCorp is required to deliver to users, and the service standards that network owners are required to deliver to VENCorp.

Finally, it is noted that the standard of service presently delivered by VENCorp reflects its probabilistic planning approach. As noted in Section 7.1.2 above, the issue of VENCorp's transmission planning standards was the subject of detailed stakeholder consultation in 2001, which culminated in VENCorp publishing a document confirming its on-going intention to apply a probabilistic approach. The planning and investment decision criteria applied by VENCorp are a key determinant of the level of network reliability. The forecasts of augmentation costs set out in this submission have been

30 In the case of the "Prescribed Services" (the bulk of all network services procured by VENCorp), charges payable by VENCorp to SPI PowerNet are subject to periodic regulatory determination pursuant to Chapter 6 of the Code.

31 As noted in Section 3.2, VENCorp is the monopoly provider of shared transmission network services in Victoria, however it owns no transmission assets. Instead, it procures "bulk" network services from asset owners such as SPI PowerNet, and uses these to provide transmission uses of system services to transmission users (namely, the main system generators and the distribution businesses.)

prepared on the assumption that VENCorp's present planning and investment criteria continue to apply. As noted in Section 8 above, any change in these standards or criteria that results in a change in costs should also trigger a corresponding change in VENCorp's total regulated revenue requirement.

ATTACHMENT 1: SUMMARY OF RELEVANT LEGAL, REGULATORY AND CONTRACTUAL INSTRUMENTS APPLICABLE TO VENCORP

Electricity Industry Act

Section 79 of the Electricity Industry Act 2000 confers on VENCorp powers and responsibility for planning and directing the augmentation of the electricity transmission system[32].

VENCorp's Electricity Transmission Licence

Clause 4 of VENCorp's electricity transmission licence states that "VENCorp is responsible for planning and directing the augmentation of the shared network"[33].

Clause 5 of the licence requires VENCorp to offer shared network services to any existing or prospective user, on fair and reasonable terms. Under Clause 5.6, VENCorp must not refuse to make an offer to provide shared network services. These provisions of the licence effectively establish an 'open access' regime for the shared network, a monopoly facility. In providing such access, it may be necessary for VENCorp to augment the capability of the shared transmission network from time to time. Thus, the obligation under law to provide the monopoly transmission service on an open access basis also gives rise to an obligation to augment the network[34].

Clause 8.1 of the licence requires VENCorp to call for offers to augment the shared transmission network from parties including SPI PowerNet, who can compete, or are capable of competing in performing transmission augmentation works.

National Electricity Code

In addition to being bound under the Victorian regulatory regime, VENCorp is also required to comply with the National Electricity Code, in its capacity as a Transmission Network Service Provider (TNSP) for the shared transmission network in Victoria. The Code specifies the access undertaking under Part IIIA of the Trade Practices Act, which governs the provision by VENCorp of access to the shared network (an "essential facility" under the Trade Practices Act) within the national electricity market.

Under Clause 5 of the National Electricity Code VENCorp must offer to provide use of system services on fair and reasonable terms to any Code participant or intending Code participant (Clause 5.3.6 (c)). VENCorp must also arrange for and participate in planning and development of its network (Clause 5.2.3(d)(4)).

Victorian System Code

32 A copy of this Act is available at www.dms.dpc.vic.gov.au.

33 The term "shared network" is defined in the licence as excluding generator and load connection facilities, because planning and augmentation of those facilities is the responsibility of the generators and distribution businesses, respectively.

34 VENCorp's electricity transmission licence was last varied on 27 March 2002, and is available at the Essential Services Commission website at http://www.reggen.vic.gov.au

The latest version of the Victorian Electricity System Code[35] was issued in October 2000 by the Office of the Regulator General. This revised System Code removes participant operational obligations, and planning and performance issues that are adequately covered by the National Electricity Code, and will continue to cover relevant Participant interface matters in Victoria, where such matters are not adequately covered by the National Electricity Code, including coverage of:

- the process and time frame for Generating Companies to develop and conduct testing in relation to generator technical requirements in the National Electricity Code, and the process for dealing with non-compliance, and
- the staged process of dealing with any non-compliance by Distribution Companies with quality of supply requirements in the National Electricity Code.

Use of System Agreements with Participants

VENCorp has a use of system agreement with each of the parties connected to the Victorian shared transmission network including Generating Companies and Distribution Businesses. These agreements require VENCorp to "use its reasonable endeavours to provide shared network capacity sufficient to meet the expected (forecast) demand at the Points of Supply". Under these agreements, VENCorp therefore has a contractual obligation to augment the shared network to continue to meet expected load growth, subject to the regulatory test promulgated by the ACCC.

The VENCorp Statement of Corporate Intent

The present Statement of Corporate Intent forms part of a VENCorp corporate plan approved by the Minister and Treasurer pursuant to Section 180 of the Gas Industry Act 2001. The Statement of Corporate Intent says that one of VENCorp's objectives is to undertake "Planning and directing the augmentation of the shared electricity transmission network to meet existing and expected future needs of customers.",

[35] A copy of the System Code is available at the Essential Services Commission website at http://www.reggen.vic.gov.au.

ATTACHMENT 2: APPLICABILITY OF PART B OF CHAPTER 6 OF THE CODE TO VENCORP

The principles, form and mechanism of economic regulation set out in Part B apply to a commercial enterprise that is in the business of owning and developing transmission networks. Part B describes an "incentive-based" regulatory regime that has the following key characteristics:

- Once every five years, the regulator determines the Network Service Provider's (NSP) maximum allowed revenue for a five-year period, based on the optimised depreciated replacement cost (ODRC) of sunk assets (the "regulatory asset base"), the regulator's estimate of the NSP's required rate of return, and the regulator's forecast of efficient incremental operating and capital costs over that period.
- The NSP must deliver the defined services over the regulatory period, and in accordance with the price or revenue control determined by the regulator. During that period, the NSP has an incentive to reduce its costs to levels below those assumed by the regulator, because the NSP is permitted to retain any cost-savings or efficiency gains it achieves during the period.
- Conversely, if the NSP incurs costs that are greater than those allowed for in its revenue or price control, the NSP bears the economic and financial consequences.
- At each five-yearly review, the regulator re-values the NSP's assets using an ODRC approach. Any inefficient investment or surplus assets are excluded from the NSP's regulatory asset base. This is intended to provide incentives for efficient investment in a regulatory regime where the maximum allowed revenue is a function of the value of the regulatory asset base.

Part B is not readily applicable to VENCorp. Some of the regulatory principles and arrangements described in Part B are inconsistent with VENCorp's role as a not-for-profit organisation that is required by the Tariff Order and its Statement of Corporate Intent to operate "on a full cost recovery but no operating surplus basis". Moreover, VENCorp is subject to separate governance arrangements, which are explicitly aimed at ensuring that VENCorp's operating costs, and network investment decisions are efficient. These considerations suggest that existing Victorian regulatory provisions relating to the approval and recovery of VENCorp's statutory electricity costs should be preserved.

ATTACHMENT 3:
VENCORP'S OPERATIONAL EXPENDITURE

This attachment provides details of VENCorp's historical and forecast operational expenditure relating to performance of its statutory electricity functions. It should be noted that although all values in this attachment are shown on a full financial year basis (to end June), this submission is only seeking operating revenue from 1 January 2003. Therefore, only 50% of the values shown for the year ending June 2003 are applicable.

1 Summary of VENCorp's historic and forecast operational expenditure

Table A3.1 provides a summary of historical operational expenditure for statutory electricity .

Historical Costs	**Historical Financials ($'000) for Year ending 30 June**			
	Actual 2000	**Actual 2001**	**Approved 2002**	**Forecast 2002**
Labour	1,550	1,489	1,969	1,772
Contracted services	501	36	216	27
Computing and communications	84	203	292	162
Consultancies and contractors	161	283	676	661
Occupancy	7	3	-	3
Vehicles and travel	58	70	197	129
Administrative	31	18	59	47
Service allocations	1721	1332	1429	1377
Depreciation	143	131	63	95
Operational Expenditure	**4,256**	**3,565**	**4,901**	**4,273**
Consulting and other income	(155)	(379)	(150)	(100)
Interest income	(803)	(1,410)	(950)	(1,746)
Bank fees and financial expenses	-	-	95	75
Non TUOS Revenues	**(958)**	**(1,789)**	**(1,005)**	**(1,771)**
Net Operational Expenditure	**3,298**	**1,776**	**3,896**	**2,502**

Table A3.1 Summary of Historical Costs

In relation to the historic costs shown in Table A3.1, it is noted that:

a) Labour costs show a modest increase over the period, predominantly reflecting increases in the number of staff. Labour costs also show a decrease in 2000/01, mainly due to difficulties in filling staff vacancies. Given the increasing workload associated with effective delivery of the statutory electricity functions, this situation is not sustainable.

b) Contracted services include the significant changes from the licences from the Essential Services Commission (previously the Office of the Regulator General) and the changing nature of the communications processes with SPI PowerNet.

c) A number of budgeted consultancies and audit programs for 1999/2000 and 2000/01 were not completed. These programs were completed in 2001/02, and it is expected that there will be an on-going requirement for these programs to be completed each year. Accordingly, the level of actual expenditure on consultancies and contractors in 2001/02 is indicative of the on-going requirement for expenditure in this area.

d) Interest income is significantly variable from year to year, due to the variable and unpredictable amount of settlement residue, settlement residue auction collections, and the resultant surplus or deficit carried forward.

e) The approved and planned operational expenditure for 2001/02 differ by $628k due to a reduction of $180k in the ESC license fee, reduced corporate costs of $50k, reduced vehicle and travel costs of $68k, delayed implementation of transmission pricing which delayed a software development project of some $130k to next financial year, and vacancies within the statutory electricity area which were unable to be filled (saving $200k). These savings have led to a 12.8% forecast expenditure below budget. As noted elsewhere in this submission, the resulting (low) level of expenditure is not sustainable.

Table A3.2 below provides a detailed summary of forecast costs for statutory electricity.

Planned Cost	Forecast Financials (in 2002 $'000) for Year ending 30 June					
	2003[36]	2004	2005	2006	2007	2008
Labour	2,235	2,357	2,436	2,636	2,722	2,814
Contracted services	219	204	205	209	211	212
Computing and communications	506	467	469	479	480	486
Consultancies and contractors	573	534	546	559	570	582
Occupancy	168	168	168	168	168	168
Vehicles and travel	161	164	166	174	176	179
Administrative	44	44	44	44	44	44
Service allocations	1,265	1,318	1,320	1,397	1,385	1,442
Depreciation	258	277	315	378	329	282
Operational Expenditure	**5,429**	**5,533**	**5,668**	**6,045**	**6,087**	**6,209**
Consulting and other income	(120)	(120)	(120)	(120)	(120)	(120)
Interest income	-	(100)	(100)	(100)	(100)	(100)
Bank fees and financial expenses	73	72	70	68	67	65
Non TUOS Revenues	**(47)**	**(148)**	**(150)**	**(152)**	**(153)**	**(154)**
Net Operational Expenditure	**5,382**	**5,385**	**5,518**	**5,893**	**5,934**	**6,055**

Table A3.2 Summary of Planned Costs

As noted in Section 6 of this submission:

- the cost forecasts for the period commencing in 2003 represent a modest increase on the costs budgeted costs for 2001/02; and

[36] Values are shown for a full financial year, however, this submission is only seeking operating revenue from 1 January 2003, which is 50% of the values shown for year ending 2003.

- the cost forecasts for the period to June 2008 are based on the Corporate Plan that has been scrutinised and approved by the Board.

The total operating cost associated with provision of VENCorp's statutory electricity functions averages just 11 cents per MWh (in real terms) over the period from 2002/03 to 2007/08. This cost represents less than 0.1% of the average cost of electricity to a typical Melbourne domestic customer.

Section 6.2 presents a detailed explanation of the main drivers of the cost increases that have been factored into the budget for the period commencing in 2002/03. In terms of the individual cost components, the material changes in costs between 2001/02 and 2002/03 are in the following categories:

a) The approved 2001/02 and forecast 2002/03 operational expenditure differ by \$528k. This is made up of a \$459k increase in corporate overheads due mainly to communications and risk management being moved into the corporate area (including the effects of the end of the superannuation holiday); and an increase of \$266k for direct labour as a result of the end of the defined benefit fund "superannuation holiday" (\$150k) and EBA (\$100k), and a small reduction in other direct expenditures.

b) Labour cost is expected to increase by \$463k for 2002/03. This reflects increases in staff numbers (mainly through filling of vacancies), increases in salary costs due to EBA payments, promotions and workcover costs. As noted above, VENCorp has experienced difficulty in recruiting suitable staff to fill all budgeted positions. This situation reflects the shortage of suitably-qualified staff in an increasingly complex industry. As a consequence, actual labour expenditure has been significantly below budget in recent years. This has placed an unsustainably high level of workload on available staff resources, with lower priority work being deferred. VENCorp has relied on consultants and contractors to undertake high priority tasks that it has been unable to complete with in-house resources. These arrangements have enabled VENCorp to meet its service delivery obligations over the last two years. However, it is considered that given the increasing workload associated with effective delivery of the statutory electricity functions, this situation is not sustainable. The increased labour cost reflects VENCorp's intention to recruit the in-house resources it will require to effectively and efficiently undertake its statutory electricity functions over the coming five years.

c) Given VENCorp's intentions regarding in-house resources, a \$88k reduction in the cost of consultancies and contractors has been budgeted for from 2001/02 to 2002/03. No material change in the cost of contracted services is expected.

d) Computing and communications costs are budgeted to increase by \$344k from 2001/02 to 2002/03, and to remain relatively constant thereafter. This reflects a transfer of this cost into this category from the "service allocations" category, and includes software and billing systems associated with the new transmission pricing arrangements in the NEM.

e) Occupancy costs increase by an apparent \$155k in 2002/03, however this reflects a transfer of this cost into this category from the "service allocations" category. Allowing for this transfer there is no net material change in the budgeted levels of costs for occupancy. Note that the occupancy values in this table include other minor expenses of a direct nature, and therefore do not match the occupancy values in Table A3.11.

f) Vehicles, travel and administrative costs are budgeted to increase by $31k from 2001/02 to 2002/03, and to remain constant thereafter. This reflects the forecast increase in NEM activity that VENCorp may be involved in and the subsequent increase in travel.

g) Depreciation is budgeted to increase by $163k from 2001/02 to 2002/03. This reflects a transfer of $186k into this category from the "service allocations" category, covering corporate workstations and corporate systems depreciation.

2 Summary of VENCorp Capital Costs

2.1 Asset values - Non-current assets plant and equipment

Table A3.3 provides a schedule of non-current assets allocated to statutory electricity.

Forecast Asset Values[37]	Forecast Financials (in 2002 $'000) for Year ending 30 June					
	2003	2004	2005	2006	2007	2008
Plant and equipment, at cost	375	444	751	783	513	543
Less accumulated depreciation	(148)	(207)	(271)	(407)	(238)	(385)
Total plant and equipment	**227**	**237**	**480**	**376**	**276**	**158**

Table A3.3 Schedule of Assets

Notes:

a) Plant and equipment consists of computing, communication and office equipment and motor vehicles.
b) The major item of expenditure is the planned data warehouse facility development in 2004/05.
c) The financial statements are prepared on the basis of historical costs and do not take into account changing money values or, except where stated, current valuations of non-current assets. Non-current assets are reviewed as considered appropriate by the Board and are not stated at amounts in excess of recoverable amounts.

2.2 Assumptions on economic life of asset for depreciation

Plant and equipment are brought to account at cost less, where applicable, any accumulated depreciation or amortisation. The carrying value of plant and equipment is reviewed annually by directors to ensure that it is not in excess of the recoverable amount from those assets. The recoverable amount is assessed in present value terms on the basis of the expected net cash flows that will be received from the assets employed and subsequent disposal.

Depreciation is charged on each fixed asset from the time the asset is held ready for use, calculated to write the cost of the asset off over the estimated useful life to the organisation using the straight-line method. The estimated useful lives for each class of assets are set out in Table A3.4 below.

[37] It is assumed that proceeds will equal the written down value of disposals.

Asset Type	Economic life Years	Depreciation rate %
Furniture and Office Equipment	10 Years	10
Computer and Communication Equipment	3 – 5 Years	20 – 33
Motor Vehicles	7 Years	15

Table A3.4 Asset lives

2.3 Depreciation and accumulated depreciation

VENCorp's forecast accumulated depreciation for assets allocated to statutory electricity is set out in Section 2.1 above. VENCorp's forecast depreciation for assets allocated to statutory electricity is set out in Table A3.5 below.

Forecast Depreciation	**Forecast Financials (in 2002 $'000) for Year ending 30 June**					
	2003	**2004**	**2005**	**2006**	**2007**	**2008**
Other plant and equipment	72	80	92	154	160	167
Written down value of disposals	59	40	66	42	68	45
Proceeds on disposals	(59)	(40)	(66)	(42)	(68)	(45)
Workstations (via Corporate)	186	197	223	224	169	115
Total depreciation	**258**	**277**	**315**	**378**	**329**	**282**

Table A3.5 Forecast depreciation

2.4 Committed capital works and capital investment

Forecast capital expenditure	**Forecast Financials (in 2002 $'000) for Year ending 30 June**					
	2003	**2004**	**2005**	**2006**	**2007**	**2008**
Other plant and equipment	123	130	401	92	128	94
Total expenditure	**123**	**130**	**401**	**92**	**128**	**94**

Table A3.6 Forecast capital expenditure

VENCorp's capital expenditure plan over the regulatory period encompasses:

a) The normal replacement of computer assets (reflected in other plant and equipment);
b) The normal replacement of plant and equipment including salary package vehicles. The written down value on disposal is assumed to equal the proceeds; and
c) the development of the data warehouse ($0.3M) in 2004/05.

2.5 Debt costs

VENCorp forecasts that its statutory electricity function will be debt free over the regulatory period.

3 Further Information Regarding Operations and Maintenance costs

3.1 Wages & salaries

Forecast wages and salaries	Forecast Financials for Year ending 30 June					
	2003	2004	2005	2006	2007	2008
Direct full time equivalent - #s	23.3	23.3	23.3	24.3	24.3	24.3
Direct labour expenses						
Labour – 2002 $'000	1,683	1,765	1,826	1,980	2,047	2,117
Labour on-costs – 2002 $'000	482	522	540	586	606	627
Training – 2002 $'000	70	70	70	70	70	70
Total forecast wages and salaries 2002 $'000	**2,235**	**2,357**	**2,436**	**2,636**	**2,722**	**2,814**

Table A3.8 Forecast wages and salaries

The labour on-costs are made up as set out in Table A3.9 below.

Component	%
Superannuation levy	11.5
Annual leave (based on historical experience VENCorp accrues annual leave at the rate of approximately 2 weeks per employee)[38]	5.8
Payroll tax	5.0
Long service leave[39]	5.6
Workers compensation insurance	2.0
Total on costs as percentage of labour	29.9

Table A3.9 Forecast labour on-costs

3.2 Cost of services by others

Forecast contracted services	Forecast Financials (in 2002 $'000) for Year ending 30 June					
	2003	2004	2005	2006	2007	2008
Licence with Essential Services Commission	50	25	25	25	25	25
IT and other	71	72	73	74	75	76
Total forecast contracted services	**121**	**97**	**98**	**99**	**100**	**101**

Table A3.10 Costs of contracted services

[38] Includes the cost of increments in provisions

[39] Includes the cost of increments in provisions

4 Information Regarding Overheads

4.1 Total service provider costs at corporate level

The total service provider costs allocated to statutory electricity are shown in table A3.11.

Forecast corporate costs	Forecast Financials (in 2002 $'000) for Year ending 30 June					
	2003	2004	2005	2006	2007	2008
General Corporate	1,265	1,318	1,320	1,397	1,385	1,442
Insurance	98	107	107	110	111	111
Computer licences	184	185	185	190	190	190
Occupancy	155	158	159	166	168	170
Depreciation	186	197	223	246	190	132
Total corporate expenses	**1,888**	**1,964**	**1,993**	**2,109**	**2,043**	**2,044**

Table A3.11 Forecast corporate costs allocated to statutory electricity

Notes:

a) General corporate expenses includes labour, corporate vehicles, administrative costs of general management and Board, Human resources, Corporate Secretary, legal and insurance management, finance, administration and reception, risk management and compliance, corporate IT management, and corporate communications.

b) Computer licences relate to the maintenance and network support agreements.

c) Depreciation relates to provision by corporate of work stations, laptops, corporate systems (payroll, finance, human resources, document management) and the corporate network.

d) From 2002/03, the total corporate expenses have been separated into "general corporate" or "service allocation" costs, and other costs as follows:

- "Insurance" for which the allocation to electricity is included in "Contracted services" in Table A3.2;
- "Computer licences " for which the allocation to electricity is included in "Computing and Communications" in Table A3.2;
- "Occupancy " for which the allocation to electricity is included in "Occupancy" in Table A3.2; and
- "Depreciation" for which the allocation to electricity is included in "Depreciation" in Table A3.2.

The "General Corporate" is shown as "Service allocations" in Table A3.2.

4.2 Allocation of costs between regulated and unregulated

All VENCorp personnel record their hours of work on a timesheet system. This data is reviewed regularly to ensure that total VENCorp (electricity and gas) costs incurred are correctly allocated between gas and electricity functions, and between costs regulated under the various different regulatory mechanisms. The forecast split of total VENCorp costs between regulated services is set out in Table A3.12 below.

Forecast corporate costs	Forecast Financials for Year ending 30 June					
	2003	2004	2005	2006	2007	2008
Regulated - gas	60.7%	59.0%	59.0%	58.2%	58.2%	58.2%
Regulated - electricity	29.2%	29.1%	29.1%	30.0%	30.0%	30.0%
Full retail contestability (oversight by ESC)	10.1%	11.9%	11.9%	11.8%	11.8%	11.8%

Table A3.12 Allocation of costs between regulated and unregulated

5 Information Regarding Key Performance Indicators

The need to provide mechanisms that enable VENCorp's performance to be scrutinised and assessed is acknowledged. VENCorp is supportive of providing relevant external performance benchmarks that will assist in assessing its performance alongside with comparable organisations. However, work completed to date by VENCorp into the possibility of benchmarking performance against other similar organisations has concluded that meaningful direct comparison with the statutory electricity functions of VENCorp is highly problematic and ineffective. NEMMCO also recently reached this conclusion in a recent attempt to benchmark its fee structures to other electricity power pool operators around the world. To the extent that meaningful external benchmark data becomes available, VENCorp will consider this data and where appropriate amend its performance monitoring regime.

Given VENCorp's desire to measure its operational performance, it has developed a series of internal corporate key performance indicators (KPIs) against which it reports to the Board and industry Participants on a monthly basis. VENCorp also publishes details of its performance against these KPIs annually through its annual report and corporate plan.

In addition, during 2001 VENCorp commissioned consultants to undertake a survey of its key stakeholders to help measure current levels of satisfaction and to determine the value of the services VENCorp provides. Responses were sought in relation to 32 services provided by VENCorp across its gas and electricity functions. The range of ratings of VENCorp's performance in delivering the ten services ranked by stakeholders as being of highest importance varied from "satisfactory" to "highly satisfied". None of VENCorp's service offerings rated below satisfactory. The results of the stakeholder survey have been communicated back to those who participated, and will be used by VENCorp to develop action plans for improving performance and optimising stakeholder value.

VENCorp has set out below some of the most important internal KPIs.

		Target year ending					
KPI	**Measure**	**June 2003**	**June 2004**	**June 2005**	**June 2006**	**June 2007**	**June 2008**
a) Electricity Operational Expenditure	$ per MWh	0.11	0.11	0.11	0.11	0.11	0.11
b) Energy Constraints	Energy not delivered (MWh)	0	0	0	0	0	0
c) Connection Enquiries	% handled in accordance with Code	100%	100%	100%	100%	100%	100%
d) Demand Forecasts	Accuracy of 10% summer forecast	+/- 2%	+/- 2%	+/- 2%	+/- 2%	+/- 2%	+/- 2%

ATTACHMENT 4:
FINANCIAL STATEMENTS

VENCorp's budget set out below has been developed based on VENCorp's statutory obligations and functions under the Electricity Industry Act, National Electricity Code and VENCorp's Transmission Licence. The forecast build up of costs does not take into account an extension of VENCorp's current statutory obligations and functions.

The key assumptions underpinning the financial forecasts are:

a) No significant change to the Transmission Network Service Provider function undertaken by VENCorp;

b) No significant change to the organisational structure of VENCorp compared to the assumptions in this submission;

c) The financial forecasts are shown in real dollars as at March 2002;

d) Rounding errors may appear in some tables;

e) All financial forecasts contained in this document are exclusive of GST.

f) The risk management, records management and compliance function is included in Corporate costs;

g) Salary costs are based on government approval of the recently negotiated EBA outcomes, and this has been extended at similar levels at later years. Direct labour expenses includes risk management, document management and compliance which has been transferred to the corporate segment and reflects the company wide responsibilities of these functions. The labour on-cost increase reflects the end of the current superannuation holiday, and an expected increase in workcover premiums;

h) Insurances and occupancy expenses shown separately (previously part of Corporate costs)

i) the labour on-cost increase reflects the conclusion of the superannuation "holiday", and an expected increase in workcover premiums;

j) insurances and occupancy expenses are now recovered to each business segment and no longer part of Corporate costs (based on headcount);

k) computer costs include the direct apportionment of the Corporate Systems

All values shown in the following tables are in real dollars as at March 2002. Where required, an annual CPI value of 2.3% has been used to convert future costs to real dollars.

TABLE 1 - STATEMENT OF FINANCIAL PERFORMANCE **$'000**

	Actual 1999/00	Actual 2000/01	Approved 2001/02	Forecast 2001/02	Plan 2002/03	Estimate 2003/04	Estimate 2004/05	Estimate 2005/06	Estimate 2006/07	Estimate 2007/08
TUoS Revenues	252,112	251,573	222,722	214,000	255,492	248,824	248,801	249,251	249,111	249,287
TuoS Disbursements[40]	(245,795)	(245,173)	(235,276)	(234,572)	(243,338)	(243,439)	(243,283)	(243,358)	(243,178)	(243,233)
Net TUoS Income / (Expense)	**6,317**	**6,400**	**(12,554)**	**(20,572)**	**12,153**	**5,385**	**5,518**	**5,893**	**5,934**	**6,054**
Consultancy and Other Revenues	155	379	150	100	120	120	120	120	120	120
REVENUE	**6,472**	**6,779**	**(12,404)**	**(20,472)**	**12,273**	**5,505**	**5,638**	**6,013**	**6,054**	**6,174**
Direct Labour Expenses	1,252	1,243	1,565	1,373	1,683	1,765	1,826	1,980	2,047	2,117
Labour On-Costs & Provisions	250	217	342	342	482	522	540	586	606	627
Training & Seminars	48	29	62	57	70	70	70	70	70	70
LABOUR COSTS	**1,550**	**1,489**	**1,969**	**1,772**	**2,235**	**2,357**	**2,436**	**2,636**	**2,722**	**2,814**
Contracted Services	500	36	216	27	121	97	98	99	100	101
Insurance	1	-	-	-	98	107	107	110	111	111
Computing	34	175	245	117	447	407	409	418	420	424
Communications	50	28	47	45	59	60	60	61	61	62

[40] The TUOS disbursements shown are estimates included in VENCorp's Corporate Plan, for the purposes of reporting Net TUoS Income/ (Expense) on the next line. These do not therefore represent anticipated TUOS disbursements.

TABLE 1 - STATEMENT OF FINANCIAL PERFORMANCE **$'000**

	Actual 1999/00	Actual 2000/01	Approved 2001/02	Forecast 2001/02	Plan 2002/03	Estimate 2003/04	Estimate 2004/05	Estimate 2005/06	Estimate 2006/07	Estimate 2007/08
Consultancies	76	240	631	616	518	479	491	504	515	527
Contractors	85	43	45	45	55	55	55	55	55	55
Vehicles & Travel	58	70	197	129	168	168	168	168	168	168
Occupancy	7	3	-	3	161	164	166	174	176	179
Administration	31	18	59	47	44	44	44	44	44	44
OPERATING EXPENSES	**2,392**	**2,102**	**3,409**	**2,801**	**3,905**	**3,938**	**4,033**	**4,269**	**4,372**	**4,485**
Depreciation & Amortisation	143	131	63	95	258	277	315	378	329	282
Service Allocations	1,721	1,332	1,429	1,377	1,265	1,318	1,320	1,397	1,385	1,442
NON-OPERATING ITEMS	**4,256**	**3,565**	**4,901**	**4,273**	**5,429**	**5,533**	**5,668**	**6,045**	**6,087**	**6,209**
OPERATING SURPLUS	**2,216**	**3,214**	**(17,305)**	**(24,745)**	**6,844**	**(28)**	**(30)**	**(32)**	**(33)**	**(35)**
Interest Income	803	1,410	950	1,746	-	100	100	100	100	100
Financing Costs	-	-	(95)	(75)	(73)	(72)	(70)	(68)	(67)	(65)
SURPLUS / (DEFICIT)	**3,019**	**4,624**	**(16,450)**	**(23,074)**	**6,771**	**-**	**-**	**-**	**-**	**-**
Prev year's Accumulated Surplus	8,660	11,679	16,450	16,303	(6,771)	-	-	-	-	-
Accumulated Surplus/(Deficit)	**11,679**	**16,303**	**-**	**(6,771)**	**-**	**-**	**-**	**-**	**-**	**-**

TABLE 2 - STATEMENT OF FINANCIAL POSITION $'000

	Actual 1999/00	Actual 2000/01	Approved 2001/02	Forecast 2001/02	Plan 2002/03	Estimate 2003/04	Estimate 2004/05	Estimate 2005/06	Estimate 2006/07	Estimate 2007/08
Cash & Short Term Deposits	15,632	20,951	5,327	4,576	6,100	6,842	6,804	7,127	7,516	7,962
Electricity Rebate Funds	-	-	-	88,779	-	-	-	-	-	-
Receivables- TuoS	19,438	20,886	20,750	14,851	21,291	20,735	20,733	20,771	20,759	20,774
Receivables- SR Disbursement	-	-	(1,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
Receivables- Other	65	85	50	319	25	25	26	26	27	27
Prepayments	-	-	-	-	-	-	-	-	-	-
Current Assets	**35,135**	**41,922**	**25,127**	**105,525**	**24,416**	**24,602**	**24,563**	**24,924**	**25,302**	**25,763**
Plant and Equipment	404	228	326	336	375	444	751	783	513	543
Accumulated Depreciation	(165)	(40)	(103)	(101)	(148)	(207)	(271)	(407)	(238)	(385)
Non-Current Assets	**239**	**188**	**223**	**235**	**227**	**237**	**480**	**376**	**276**	**158**
TOTAL ASSETS	**35,374**	**42,110**	**25,350**	**105,760**	**24,643**	**24,839**	**25,043**	**25,300**	**25,578**	**25,921**
Payables- TUoS	19,995	21,132	21,470	19,548	20,278	20,287	20,274	20,280	20,265	20,269
Payables- Settlement Residue	1,784	3,658	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Payables- Electricity Rebate	-	-	-	88,779	-	-	-	-	-	-
Payables- Other	1,126	144	-	200	200	200	200	200	200	200
Employment Entitlements	430	459	470	528	613	711	825	957	1,111	1,289

TABLE 2 - STATEMENT OF FINANCIAL POSITION $'000

	Actual 1999/00	Actual 2000/01	Approved 2001/02	Forecast 2001/02	Plan 2002/03	Estimate 2003/04	Estimate 2004/05	Estimate 2005/06	Estimate 2006/07	Estimate 2007/08
Current Liabilities	**23,335**	**25,393**	**24,940**	**112,055**	**24,091**	**24,198**	**24,299**	**24,437**	**24,576**	**24,758**
LT Employment Entitlements	360	414	410	476	552	641	744	863	1,002	1,163
Non-Current Liabilities	**360**	**414**	**410**	**476**	**552**	**641**	**744**	**863**	**1,002**	**1,163**
TOTAL LIABILITIES	**23,695**	**25,807**	**25,350**	**112,531**	**24,643**	**24,839**	**25,043**	**25,300**	**25,578**	**25,921**
NET ASSETS	**11,679**	**16,303**	**-**	**(6,771)**	**-**	**-**	**-**	**-**	**-**	**-**
Contributed Capital	-	-	-	-	-	-	-	-	-	-
Tariffed Electricity Reserve	8,660	11,679	16,450	16,303	(6,771)	-	-	-	-	-
Surplus/(Deficit)	3,019	4,624	(16,450)	(23,074)	6,771	-	-	-	-	-
EQUITY	**11,679**	**16,303**	**-**	**(6,771)**	**-**	**-**	**-**	**-**	**-**	**-**

TABLE 3 - STATUTORY ELECTRICITY STATEMENT OF CASH FLOWS **$'000**

	Actual 1999/00	Actual 2000/01	Approved 2001/02	Forecast 2001/02	Plan 2002/03	Estimate 2003/04	Estimate 2004/05	Estimate 2005/06	Estimate 2006/07	Estimate 2007/08
Opening Cash Balance	**11,880**	**15,632**	**20,951**	**20,951**	**93,355**	**6,100**	**6,842**	**6,804**	**7,127**	**7,516**
Cash Flows from Operating Activities										
Receipts from Customers	252,610	250,504	223,008	220,135	249,172	249,500	248,923	249,333	249,243	249,392
Payments to Suppliers & Employees	(251,349)	(248,369)	(239,766)	(240,147)	(247,805)	(248,696)	(248,656)	(248,992)	(248,826)	(248,932)
Interest Received	738	1,390	985	1,512	294	100	99	100	99	100
Interest Paid	-	-	(95)	(75)	(73)	(72)	(70)	(68)	(67)	(65)
	1,999	**3,525**	**(15,868)**	**(18,575)**	**1,587**	**832**	**296**	**373**	**449**	**495**
Cash Flows from Investing Activities										
Capital Expenditure	(75)	(102)	(98)	(203)	(123)	(130)	(401)	(92)	(128)	(94)
Proceeds from Asset Sales	44	22	-	61	59	40	66	42	68	45
	(31)	**(80)**	**(98)**	**(142)**	**(64)**	**(90)**	**(335)**	**(50)**	**(60)**	**(49)**
Cash Flows from Settlement Residue, Settlement Residue Auction and Country Price Compensation Payment Activities										
Receipt of Settlement Residue	26,540	75,912	96,182	96,182	57,969	57,993	57,956	57,974	57,931	57,944
Payments of Settlement Residue	(24,756)	(74,038)	(95,840)	(93,840)	(57,969)	(57,993)	(57,956)	(57,974)	(57,931)	(57,944)
Receipt of Electricity Payment	-	-	-	118,842	1,411	-	-	-	-	-
Payments of Electricity Payment	-	-	-	(30,063)	(90,190)	-	-	-	-	-

TABLE 3 - STATUTORY ELECTRICITY STATEMENT OF CASH FLOWS

$'000

	Actual 1999/00	Actual 2000/01	Approved 2001/02	Forecast 2001/02	Plan 2002/03	Estimate 2003/04	Estimate 2004/05	Estimate 2005/06	Estimate 2006/07	Estimate 2007/08
	1,784	**1,874**	**342**	**91,121**	**(88,779)**	**-**	**-**	**-**	**-**	**-**
Cash Surplus / (Shortfall)	**3,752**	**5,319**	**(15,624)**	**72,404**	**(87,255)**	**742**	**(38)**	**323**	**389**	**446**
CLOSING CASH BALANCE	**15,632**	**20,951**	**5,327**	**93,355**	**6,100**	**6,842**	**6,804**	**7,127**	**7,516**	**7,962**

TABLE 4 - RECONCILIATION OF CASH FLOWS TO FINANCIAL PERFORMANCE

$'000

	Actual 1999/00	Actual 2000/01	Approved 2001/02	Forecast 2001/02	Plan 2002/03	Estimate 2003/04	Estimate 2004/05	Estimate 2005/06	Estimate 2006/07	Estimate 2007/08
Operating Surplus	**3,019**	**4,624**	**(16,450)**	**(23,074)**	**6,771**	**-**	**-**	**-**	**-**	**-**
Non-Cash items in Operating Surplus										
Depreciation	148	135	63	95	72	80	92	154	160	167
(Gain) / Loss on Asset Disposal	(5)	(4)	-	-	-	-	-	-	-	-
Decreased Current Assets	278	(1,468)	171	5,801	(6,146)	556	1	(38)	11	(15)
Increased Liabilities	(188)	155	341	(1,528)	729	9	(14)	6	(15)	4
Increased Employee Entitlements	(1,253)	83	7	131	161	187	217	251	293	339
Net Cash Flows from Operating Activities	**1,999**	**3,525**	**(15,868)**	**(18,575)**	**1,587**	**832**	**296**	**373**	**449**	**495**

TABLE 5 - STATUTORY ELECTRICITY HEADCOUNT — **Full Time Equivalents**

	Actual 1999/00	Actual 2000/01	Approved 2001/02	Forecast 2001/02	Plan 2002/03	Estimate 2003/04	Estimate 2004/05	Estimate 2005/06	Estimate 2006/07	Estimate 2007/08
Energy Markets	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Operations	-	-	-	-	-	-	-	-	-	-
Energy Infrastructure	17.0	16.8	18.5	19.5	20.2	20.2	20.2	21.2	21.2	21.2
Information Technology	1.4	0.7	1.4	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Commercial	-	-	-	-	-	-	-	-	-	-
Communications	-	-	-	-	-	-	-	-	-	-
Employees	**20.4**	**19.5**	**21.9**	**22.6**	**23.3**	**23.3**	**23.3**	**24.3**	**24.3**	**24.3**
Contractors	1.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Labour Force	**21.4**	**20.0**	**22.4**	**23.1**	**23.8**	**23.8**	**23.8**	**24.8**	**24.8**	**24.8**

TABLE 6 - VENCorp CONSOLIDATED HEADCOUNT — **Full Time Equivalents**

	Actual 1999/00	Actual 2000/01	Approved 2001/02	Forecast 2001/02	Plan 2002/03	Estimate 2003/04	Estimate 2004/05	Estimate 2005/06	Estimate 2006/07	Estimate 2007/08
Energy Markets	9.5	8.5	9.5	9.5	9.8	10.3	10.3	10.3	10.3	10.3
Operations	26.0	26.0	26.0	25.5	25.5	25.5	25.5	25.5	25.5	25.5
Energy Infrastructure	23.0	26.5	23.5	24.5	24.2	24.2	24.2	25.2	25.2	25.2
Retail Contestability	-	1.0	1.0	7.6	9.1	8.5	8.5	8.5	8.5	8.5
Information Technology	15.1	14.3	14.0	13.5	12.7	12.7	12.7	12.7	12.7	12.7
Commercial	11.0	12.0	7.6	8.0	8.8	8.5	8.5	8.5	8.5	8.5
Communications	4.0	4.0	2.0	-	1.0	1.0	1.0	1.0	1.0	1.0
Humans Resources	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
General Management	2.0	2.0	2.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Employees	**92.6**	**96.3**	**87.6**	**92.2**	**94.7**	**94.3**	**94.3**	**95.3**	**95.3**	**95.3**
Contractors (includes FRC Project)	11.0	9.0	17.0	25.0	14.0	6.0	4.0	4.0	4.0	4.0
Labour Force	**103.6**	**105.3**	**104.6**	**117.2**	**108.7**	**100.3**	**98.3**	**99.3**	**99.3**	**99.3**

Note

In the Performance Statement FBT, Entertainment and Staff Amenities transferred from Administration to Vehicles and Travel

TABLE 7 – Corporate Service Level Allocations

	Actual 1999/00	Actual 2000/01	Approved 2001/02	Forecast 2001/02	Plan 2002/03	Estimate 2003/04	Estimate 2004/05	Estimate 2005/06		Actual 1999/00
Insurance					98	107	107	110	111	111
Computers					184	185	185	190	190	190
Occupancy					155	158	159	166	168	170
Corporate Computer Depreciation					186	197	223	246	190	132
SLA General	1,721	1,332	1,429	1,377	1,265	1,318	1,320	1,397	1,385	1,442
	1,721	**1,332**	**1,429**	**1,377**	**1,888**	**1,964**	**1,993**	**2,109**	**2,043**	**2,044**

ATTACHMENT 5:
VENCorp's Electricity Planning Criteria

1. Overall approach to investment decision analysis

VENCorp will continue to:

- apply an approach that is consistent with the requirements of the ACCC's "net market benefits test" in the economic evaluation of transmission investment decisions; and
- apply a probabilistic approach[41], where practicable, except in those cases where VENCorp is required to meet a performance standard under Schedule 5.1 of the Code.

2. Management of risk associated with the probabilistic approach

Under the "probabilistic approach", transmission augmentation proceeds only when the total expected (probability-weighted) cost of not proceeding exceeds the cost of the investment required to remove those costs. This approach provides a sound actuarial estimate of the expected net benefits of network augmentation. However, under this approach, there may be circumstances when the planned capability of the network will be insufficient to meet actual demand, even with all network elements in service.

Consequently, VENCorp's investment evaluations will have regard to the potential costs associated with very high-cost, low-probability events that may impact on network capability. However, the Board has decided that VENCorp will not implement mechanisms aimed at capping exposures to high-cost, low-probability events that may affect transmission system capability, as such mechanisms are likely to be impracticable and ineffective.

3. Treatment of "externalities" in the analysis of investment decisions

Externalities are external benefits and costs which are not captured through normal market mechanisms. These may include environmental, political and social impacts. VENCorp will continue to adhere to its policy of not including externalities in the economic evaluation of transmission investment decisions. However, VENCorp will provide information on externalities associated with its decisions, so that Government, market participants and other stakeholders may be informed of such issues, where they may have a bearing on the investment decision.

[41] The key features of the "probabilistic approach" are described in detail in VENCorp's Consultation Paper.

4. Valuation of supply reliability VENCorp will continue with its existing policy relating to the use of the $10,000 "VoLL" wholesale market price cap in transmission investment decisions. However, the Board has directed management to undertake further research into the valuation of customer reliability. The Board has also amended the policy to enable sensitivity testing of the transmission investment decision signal to be undertaken for a composite (market-wide average) valuation of customer reliability of up to $28,000 per MWh, on the basis that this value is: • a reasonable estimate of the value of supply reliability to consumers, derived from the study undertaken by Monash University in 1997; and • is consistent with the value implied by the "deterministic" generation reliability standard set by the Reliability Panel. The policy has also been amended to enable the application of sector-specific valuations of customer reliability in transmission investment decisions, where this is appropriate.
5. Consultation with stakeholders The Board re-affirmed VENCorp's strong commitment to consulting with stakeholders on a project-by-project basis, on all relevant factors during the planning and investment decision process. VENCorp will continue to adhere to its present policy of conducting detailed consultation on each proposed project. That consultation will include, among other things, consideration of the merit and practicability of applying sector-specific estimates of the value of customer reliability.

VENCorp's electricity transmission network planning criteria

Following the conclusion of its consultation, the VENCorp Board approved the following major action items to further improve VENCorp's application of probabilistic planning:

1. VENCorp will undertake further research into consumer interruption costs and the valuation of customer reliability in transmission investment decision analysis. That research will consider, among other things:

    - the validity of the "VoLL" wholesale market price cap as an indicator of the value of customer reliability that should be applied in transmission investment decision analysis;
    - the need to maintain neutrality between centrally-coordinated transmission investment decisions and commercial decisions of wholesale market participants; and
    - the practicability and merit of applying sector-specific estimates of the value of customer reliability.

    VENCorp will launch a separate consultation process if this research indicates that there may be merit in amending the present policy regarding the valuation of customer reliability in transmission investment decisions.

2. VENCorp will undertake further action to improve the present probabilistic analyses, including analysing the extent of any bias in the method by which plant failure probabilities are calculated.

3. VENCorp will continue to provide information on its transmission planning and investment criteria to NECA for consideration in the context of NECA's review of the network reliability standards in schedule 5.1 of the National Electricity Code.

ATTACHMENT 6:
VENCorp's Augmentation Projects

1 Committed Augmentation

1.1 South Morang Series Capacitors

For this project, two 50% compensated series capacitors were installed on the Dederang to South Morang 330 kV lines at the South Morang terminal station. The project included replacement of the existing line protection on the compensated lines and was the first time series capacitor banks were installed on a transmission network in Australia.

The project was required because the growth of air-conditioning load had degraded the capability to import power from New South Wales/Snowy on hot summer days when power demands are at their peak. To avoid voltage collapse in Melbourne under these peak load conditions it had become necessary to reduce the maximum import over the interconnection from the nominal maximum capacity of 1,500 MW to around 1,100 MW. The series capacitor banks have allowed the two 330 kV transmission lines that form the interconnection to operate at their thermal rating, restoring their capability to import and export electricity.

A probabilistic-based economic assessment of options for restoring interconnection transfer capability at times of peak Victorian electricity demand was carried out. The assessment considered the reduction in "energy at risk" (that is, the expected energy not supplied to electricity customers taking into account the probability of an occurrence of the critical loading and generating conditions) and the impact the series capacitors would have on other network augmentation projects due to the changed power flow patterns.

The economic assessment showed that the benefit from installation of series capacitors was significantly greater than the cost of the project.

The project was put out to competitive tender in mid-1997. In competition with others, GPU PowerNet (now SPI PowerNet) was the successful bidder to provide the transmission service on a build, own and operate basis, in return for payment of an annual fee for the service over its life.

This project was the first contestable electricity transmission services contract in Australia, and one of the first world-wide.

The contracts for the contestable works were in two parts. The contract for project construction and commissioning set out the performance obligations and the detailed design brief and included liquidated damages clauses for late delivery. The second contract covered the terms and conditions for the delivery of the service over the life of the contract. Key features were the definition of performance requirements, liabilities and financial arrangements to apply over the life of the service. This inclusion of performance incentives provides a basis for the service provider to determine the appropriate reliability of plant. The incentives were sculptured to encourage high availability at the times when the service is critical to the system and to signal the appropriate times to scheduled planned outages.

To integrate the capacitor banks into the transmission network it was necessary for PowerNet to undertake non-contestable works at South Morang and other locations. A separate interface services contract was negotiated directly with PowerNet on fair and reasonable terms.

1.2 500kV Protection Upgrade

The scope of the works included replacing and upgrading of existing protection on the Loy Yang to Hazelwood, South Morang to Sydenham, and South Morang to Keilor 500 kV lines, all of which are located at sites owned and operated by SPI PowerNet.

The project was required to improve the functionality of the protection systems for selected 500 kV transmission lines. Increased power flows on these lines was seen to create some system operating conditions which could degrade the security of these protection systems with an increased risk that a fault on one of these lines could result in a cascade trip of several 500 kV lines, potentially resulting in a total shutdown of the Victorian Power System.

As these new protections are an integral part of the existing protection systems on the PowerNet 500 kV lines it was not practical for a third party to own, operate and maintain the new protection, and therefore VENCorp negotiated a contract with PowerNet on fair and reasonable terms.

The project service date was mid 2000.

1.3 Rowville Transmission Services

This project involved installation of a new 500/220 kV 1000 MVA transformer at Rowville terminal station and came into service in November 1999. The project included establishment of a new 500 kV switchyard and 500 kV switching at Rowville.

This project was required to provide a secure and reliable supply to the growing major load block in the eastern metropolitan area of Melbourne. Prior to the installation of the Rowville transformer, all load growth in this area had to be supplied from the 500 kV network via South Morang and Keilor and the 330/220 kV South Morang transformers were a constraint on support of this load under peak loading conditions. A number of network options were considered with the Rowville option providing the best cost/benefit outcome. The installation of the Rowville transformer provided a means of supplying power directly into the eastern metropolitan area from the 500 kV network, removing the risk of load shedding under peak loading conditions.

Probabilistic studies indicated that the avoided expected unsupplied energy and the reduction in losses provide significant economic benefit from the network augmentation for installation in 1999 and was greater than the cost of the project.

The project was put out to competitive tender and in April 1998 Eastern Energy was awarded the contract to build, own and operate the station. This was the second contestable transmission services contract in Australia and the first awarded to a non-incumbent transmission owner.

The contracts for the contestable works were in two parts. The contract for project construction and commissioning set out the performance obligations and the detailed design brief and included liquidated damages clauses for late delivery. The second contract covered the terms and conditions for the delivery of the service over the life of the contract. Key features were the definition of performance requirements, liabilities and financial arrangements to apply over the life of the service. This inclusion of performance incentives provides a basis for the service provider to determine the appropriate reliability of plant. The incentives were sculptured to encourage high availability at the times when the service is critical to the system and to signal the appropriate times to scheduled planned outages.

To enable connection of the new transformation into the existing transmission network, PowerNet were required to undertake non-contestable works at Rowville and other locations. This included a bus split and major rearrangement of 220 kV lines at the adjacent Rowville 220 kV station. A separate interface services network agreement was negotiated directly with PowerNet on fair and reasonable terms.

In 2000, Eastern Energy (now TXU) sold the facility to Rowville Transmission Facility Pty Ltd and the Network Agreement with VENCorp was appropriately novated to the new owner.

1.4 SNOVIC Interconnection upgrade

At the request of the Victorian Government, VENCorp undertook a study into the feasibility of upgrading the Snowy to Victorian interconnector. In its report, dated 29 March 2001, VENCorp concluded that a 400 MW interconnection upgrade by summer 2002/03 for an estimated capital cost of $44 million, is the most cost-effective source of additional capacity of all the options considered, and is likely to meet the requirements of the ACCC's market benefits test for regulated transmission developments.

SNOVIC is an economic project as it has:

- a relatively low capital cost per unit of capacity; *and*
- reasonably abundant surplus (sunk) generating capacity available in New South Wales for export to Victoria.

The augmentations required to achieve this upgrade include:

- Increasing the thermal rating of the South Morang – Dederang – Murray 330 kV transmission lines;
- Reconfiguring of switching arrangements on the Dederang-Glenrowan-Shepparton lines;
- Installing shunt capacitor banks at Dederang and Wodonga Terminal Stations; and
- Some works in NSW on 132kV and 330kV networks.

VENCorp subsequently acted as the proponent for SNOVIC for the purposes of gaining regulatory approvals through NEMMCO's Inter Regional Planning Committee ("IRPC"). This process was commenced on 17 May 2001, and was completed on 31 October when the IRPC announced that it was recommending to the NEMMCO Board that the SNOVIC project be approved as a regulated interconnector. This recommendation was made after the IRPC undertook extensive technical and economic evaluation of the project including considerable consultation processes.

The final step in the regulatory approvals process was the NEMMCO Board's approval of SNOVIC as a regulated interconnector service on 6 December 2002.

The works are currently being undertaken by a number of parties as follows:

- SPI PowerNet is undertaking the non contestable line upgrade and switching re-arrangement works;
- ABB is the successful tenderer for provision of the capacitor banks on a build, own and operate basis;
- TransGrid is undertaking work on its assets in NSW (132kV and 330kV line modifications); and
- Snowy Mountains Hydro Authority is undertaking work on its assets (termination equipment at Murray Switching Station)

1.5 Reactive Support for 2001/02 to 2003/04

In the Victorian power system the maximum summer demand that can be supported by the transmission network is determined by the voltage collapse limit over a range of generation and other operating conditions. In September 2000, VENCorp carried out a consultation process in relation to the assessment of the additional network reactive support required for the period from summer 2001/02 to 2003/04 inclusive.

The consultation process was based on the guidelines in the National Electricity Code and provided market participants and interested parties the opportunity to comment on the proposals and timing and to offer alternative solutions, including demand management, cogeneration and power factor improvement. The consultation process determined that the realistic and preferred solution was the installation of additional shunt capacitor banks at defined locations on the network.

Taking into account the expected value of load at risk and the cost of increasing reactive capability to reduce the load at risk, it was determined that it was economic to raise the voltage collapse limit of the transmission system by installation of an additional 400 MVAr of shunt capacitor banks prior to the summer of 2001/2002 and an additional 200 MVAr prior to summer 2002/03. The possibility of a further 200 MVAr for 2002/03 or 2003/04 was also identified depending on load growth and other developments.

VENCorp carried out a competitive tender process in late 2000 for the provision of the additional reactive support services. This was the first contestable transmission services contract for shunt capacitors and was made feasible by the packaging of a number of banks together. SPI PowerNet was selected as the successful tenderer and a contract was awarded in January 2001 to build, own and operate the 600 MVAr shunt capacitor banks and provide an additional 200 MVAr option if required.

400 MVAr were placed in service by 1 December 2001 and 200 MVAr is on target for service by December 2002. A review of reactive requirements for summer 2002/03 has determined that the

optional 200 MVAr capacitor bank, in the reactive support tender for summer 2001/02 to 2003/04, is not required for summer 2002/03 and will be reconsidered for service by 1 December 2003.

As with other contestable projects, the contracts are in two parts. The contract for project construction and commissioning sets out the performance obligations and the detailed design brief and includes liquidated damages clauses for late delivery. The second contract covers the terms and conditions for the delivery of the service over the life of the contract. Key features were the definition of performance requirements, liabilities and financial arrangements to apply over the life of the service. This inclusion of performance incentives provides a basis for the service provider to determine the appropriate reliability of plant. The incentives were sculptured to encourage high availability at the times when the service is critical to the system and to signal the appropriate times to scheduled planned outages.

2 Planned Augmentations

Further detail on all the following augmentation can be found in VENCorp's 2002 Annual Planning Review.

2.1 Optimisation of Latrobe Valley to Melbourne 500kV transmission

The Victorian power system is heavily dependent on the 500 kV transmission network from the Latrobe Valley to the Melbourne area to connect about 5600 MW of generation to the Victorian load centre. Over 90% of the Latrobe Valley generation uses brown coal as fuel, and as these units are among the lowest fuel cost generators in the National Electricity Market (NEM), they run at almost full utilisation, unless limited by transmission constraints. An outage of one of the 500 kV transmission lines between Latrobe Valley and Melbourne may constrain the amount of Latrobe Valley generation that can be transmitted because of voltage collapse, thermal or transient stability limitations.

Capacity of the transmission network is sufficient to transport existing and proposed generation capacity, including the proposed interconnection to Tasmania, Basslink, with all 500 kV transmission lines in service. With one 500 kV line out of service up to 1550 MW of generation may need to be reduced from the existing level and up to 2150 MW with the proposed generation additions and interconnection. If this event were to occur then the Latrobe Valley generation would need to be replaced by high cost generation and if insufficient then by load shedding.

Transmission losses (both active and reactive) on the 220 kV network from Latrobe Valley to Melbourne area is comparatively high compared with the 500 kV network. The 4th 500 kV line, which is operating at 220 kV, is under-utilised in terms of its design capacity of 3400 MVA. In addition, this arrangement increases transmission losses and reduces voltage collapse and system stability limits.

A number of transmission, demand side and generation options have been identified to alleviate the 500 kV transmission constraints. Detailed planning studies have been undertaken in accordance with the ACCC's regulatory test, as promulgated by the ACCC in December 1999, to consider the options and timing for optimising the Latrobe Valley to Melbourne 500 kV network.

Conversion of the fourth 500 kV line from the Latrobe Valley to Melbourne from 220 kV operation to 500 kV with new 500/220 kV 1000 MVA transformation in Melbourne's east at either Rowville or Cranbourne has been shown to best satisfy the ACCC regulatory test by maximising market benefits for most scenarios and by achieving lower cost for most scenarios.

A public consultation has been carried out and no objections to the VENCorp assessment were received and no other alternatives were identified.

VENCorp will commence a tendering process in May 2002 for the 500/220 kV transformation works. VENCorp will negotiate directly with SPI PowerNet to contract for the non contestable line upgrade and station works and the interface works.

Optimum timing of the project is December 2003.

2.2 Melbourne Metropolitan Transformation

To meet the on-going growth in load in the Melbourne metropolitan area it will be necessary to strengthen the power supply into the metropolitan 220 kV ring. This capability is presently met by the existing transformation at 500/220 kV, 500/330kV and 330/220 kV, however the spare capacity in this plant is being used up by the load growth and additional transformation will be required. For scenarios where generation is connected on the 500 kV network (such as in the Latrobe Valley) then 500/220 kV transformation will be favoured. However in the case where there is a significant strengthening of the interconnection with Snowy/NSW then 500/330Kv and 330/220 kV transformation at South Morang is likely to be a better option.

The extent and timing of augmentations will depend on the how much the growth is met by local generation (connected at or below the 220 kV level) and demand side management and the source of the new main system generation.

A 1000MVA 500/220 kV transformer could be required as early as Dec 2005 under some scenarios with a second 1000 MVVA transformer needed towards 2012. With higher metro generation/DSM the timing for each would be deferred. If generation is being sourced from increased transfer then the transformer augmentations will mainly be linked with the interconnection works.

2.3 Reactive Supply

Reactive load is growing with the growth in active load. It is forecast that 300 MVAr of reactive capacity is required on average per year to meet the growth in reactive load and losses. It is estimated that around 100 MVAr of this will be provided from increased generation, distribution network power factor corrections and transmission augmentations. The remaining 200 MVAr will need to be provided from shunt capacitors installed on the transmission system.

VENCorp has a contract in place with SPI PowerNet for 200 MVAr for service by December 2002 with an option for a further 200 MVAr for service by December 2003.

Additional requirements will be assessed on an annual basis having regard to load growth and the other developments, which impact on the reactive demand. Recent practice has been to acquire this reactive through a contestable process and it is expected that this would continue in the future.

2.4 Fault Level Management

The management of fault levels is a major issue for the development of the metropolitan transmission system. This is a particular issue for the Melbourne metropolitan area where the fault level at many stations is now very close to the plant capability. Fault levels across the system are generally increasing with the addition of new generation, interconnectors, transmission lines and transformers.

Special switching arrangements are now utilised to contain 220 kV fault levels at critical terminal stations including Hazelwood, Rowville, Thomastown, and Keilor. At these locations selected circuit breakers are opened to split 220 kV busbars or to rearrange the switching configuration of certain transmission lines. Although this technique reduces the fault level to within the plant capability, it also reduces the ability to fully utilise the installed transmission to meet the load transfer requirements. It also results in increased operational complexity and therefore increases the risk of unplanned outages due to switching errors.

Replacement of the limiting switchgear, preferably as part of switchgear refurbishment programs, is the preferred option, as it results in both the highest utilisation of the existing assets and the most flexible and simple operational arrangements. However, most of the critical switchgear is not planned for retirement within the foreseeable future, and it is envisaged that it will be necessary to replace the switchgear solely because of fault levels.

It is anticipated that this would be achieved by direct negotiation with the transmission asset owner.

Location and timing will depend on the development on new generation plant.

2.5 Interconnection Works

The high import scenarios involve significant works to increase the transfer capability from Snowy/NSW to Victoria. The proposal being contemplated would require 330 kV line and series compensation works in both southern NSW and in Victoria. In particular a third Dederang to South Morang 330 kV line and series compensation would be required along with uprating of the existing two Dederang to South Morang lines and series compensators as well as series compensators on the Eildon to Thomastown lines and new capacitor banks at a northern terminal station.

As described above, this scenario also requires the development of the transformation at South Morang.

VENCorp would anticipate major portions of these works would be contestable.

Timing depends on the timing for the interconnection upgrades.