ECONOMIC EVALUATION

OPTIMISING THE LATROBE VALLEY TO MELBOURNE ELECTRICITY TRANSMISSION CAPACITY

FEBRUARY 2002

DISCLAIMER

This report describes the economic evaluation studies undertaken by VENCorp for optimising the Latrobe Valley to Melbourne electricity transmission capacity. Under the Electricity Industry Act and its transmission licence, VENCorp is responsible for planning and developing the shared transmission system in Victoria to provide, in an economic manner, a reliable and cost-effective means of transferring energy from generators to customers.

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1 Introduction

VENCorp has undertaken a review of the power transmission capacity between the Latrobe Valley and Melbourne. This review indicates that the transmission capability can be optimised in an economic manner by augmenting the transmission network.

The benefits of optimising the power transmission capacity between the Latrobe Valley and the Melbourne metropolitan area include:

1. Reduction in transmission active power losses;
2. Reduction in the amount of generation re-scheduling and potential load shedding due to transmission constraints during both planned and unplanned outages; and
3. Reduction in reactive power losses under heavy system loading, which reduces the requirement to install new reactive plant.

VENCorp has initiated a consultation process with regard to the options for achieving this optimisation. The details of that consultation, together with an overall discussion of the key issues associated with proposed optimisation, are contained in the report *"Consultation Paper on Optimising the Latrobe Valley to Melbourne Electricity Transmission Capacity".*

This report, with supports the Consultation Paper, outlines the economic assessment methodology, market development scenarios, simulation data, net benefit analysis and recommendations for optimisation.

The accompanying report "*Technical Report [5] on Optimising the Latrobe Valley to Melbourne Electricity Transmission Capacity"* describes the limitations of the existing transmission system, and outlines a number of possible development options to optimise the capacity of the transmission system that are likely to satisfy the required regulatory tests for transmission augmentations.

In accordance with clause 5.6.2 of the National Electricity Code, all transmission investment must satisfy the regulatory test as promulgated by the ACCC in December 1999. Clause 5.6.2(g) of the code states that;

> Each *Network Service Provider* must carry out an economic cost effectiveness analysis of possible options to identify options that satisfy the regulatory test, while meeting the technical requirements of schedule 5.1 of the *Code* and where the *Network Service Provider* is required by clause 5.6.2(f) to consult on the option this analysis and allocation must form part of, the consultation on that option.

This report presents the cost effectiveness study carried out by VENCorp on optimising the Latrobe valley to Melbourne electricity transmission capacity. The report includes:

- an overview of the economic evaluation in Section 2;
- a description of the net benefit assessment including the market development scenarios, generation expansion and market simulation in Section 3;
- a description of assumptions and simulation data used in the assessment, and the results of the net benefit test in Section 4 and 5; and
- an analysis of results of the net benefit test, the conclusion and the recommendations in Sections 6, 7 and 8.

2 Background

2.1 Overview

Under the Electricity Industry Act and its transmission licence, VENCorp is responsible for planning and developing the transmission system to provide, in an economic manner, a reliable and cost-effective means of transferring energy from generators to customers. Typically, transmission investment decisions are characterised by a trade-off between increasing supply reliability and increasing the level of transmission capacity. In many cases, the economic benefit of additional transmission capacity is an increase in the level of supply reliability (and hence a reduction in expected unserved energy). However, transmission investments can also deliver other benefits, in the form of:

- reduced transmission losses.
- reduced ancillary services costs; and
- reduced energy costs (dispatch costs) in the market, due to a more efficient dispatch of generation resources.

The fourth 500 kV line was established between the Latrobe Valley and Melbourne in the late 1980s to increase the level of transfer capability between Victoria's major generation and load centres. The line has been operated at 220 kV since that time to optimise the use of the existing assets, and to defer the need for additional 500/220 kV transformation. This arrangement presently provides adequate capacity to meet the existing transfer requirements.

Planning studies undertaken by VENCorp indicate that up-rating the present 220 kV line to 500 kV may be economically justified on the basis of higher economic benefits.

The project principally involves the connection of the line to the 500 kV network at Hazelwood and in the metropolitan area and the installation of new 500/220 kV transformation in the eastern metropolitan area of Melbourne. The total capital cost of the project is estimated to be about $24 million for the transformer to be installed at Rowville and $36 million for the transformer to be installed at Cranbourne.

The magnitude of the benefits provided by the project depends on a number of factors. One of these factors is the level of generation sent out of the Latrobe Valley to Melbourne. It is expected however, that over a wide range of plausible scenarios relating to Latrobe Valley to Melbourne transfers, there would be significant reductions in losses and energy constraints as a result of the project. This is illustrated in the diagram below.

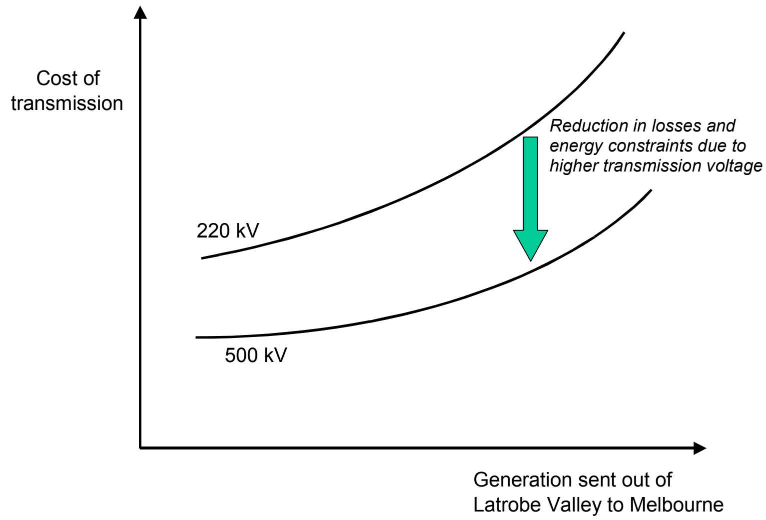

Figure 2.1: Transmission costs and generation sent out

Note: Cost of transmission includes transmission loss and transmission constraint related costs.

Other factors that may influence the economics of the project include:

- the timing and sequence of entry of new generation and/or MNSP capacity into the Victorian region; and
- the availability and cost of alternative projects that deliver reductions in transmission losses and constraints.

2.2 Regulatory test requirements

This assessment is being carried out as a requirement under the ACCC's regulatory test.

The ACCC's regulatory test states:

> "An *augmentation* 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*".

Market benefit is defined as:

> "the total net benefits of the proposed augmentation to all those who produce, distribute and consume electricity in the National Electricity Market. That is, the increase in consumers' and producers' surplus or another measure that can be

demonstrated to produce equivalent ranking of options in most (although not all) credible scenarios".

According to the regulatory test, an augmentation satisfies the test if the augmentation maximises the net present value of the market benefit. The test also states that the proposed augmentation maximises the market benefit if it achieves greater market benefit in most (although not all) credible scenarios.

2.3 Objective of the economic evaluation

The objective of the economic evaluation is to identify the most economic means of increasing the level of energy efficiency within the Victorian power system, in accordance with the requirements of paragraph (b) of the regulatory test. In other words:

- the evaluation would not be conducted as a cost-effectiveness study against a pre-determined target level of transmission losses and energy constraint level;
- the project would have to generate a positive net present value (NPV); and
- across a range of scenarios, the project would have to maximise the NPV of the market benefit, having regard to the alternative projects that would be available to increase the level of energy efficiency within the Victorian power system.

The accompanying "*Consultation paper"* provides a summary of the key issues of the economic evaluation. The accompanying "*Technical Report" [5]* describes in detail the existing system issues, technical requirements, transmission development options that is likely to satisfy the regulatory test and transmission constraint equations to be used for the cost effectiveness analysis.

3 Methodology

The methodology, which has been applied to the evaluation, is based on the ACCC regulatory Test. The data, which was used in the evaluation, is discussed in Section 4 of this report.

3.1 Assessment Criterion

3.1.1 Benefits of Project

VENCorp has determined that the transmission augmentation benefits, which will be considered as part of this evaluation, to be as follows;

Benefit 1. Reduction in energy that must be curtailed to ensure that the Latrobe Valley to Melbourne 500 kV transmission system does not operate beyond its rated capability. The critical contingency for the Latrobe Valley to Melbourne network is outage of one of the Hazelwood Terminal Station (HWTS) to South Morang Terminal Station (SMTS) or HWTS to Rowville Terminal Station (ROTS) 500kV lines.

Benefit 2. Reduction in generation dispatch costs to ensure that the Latrobe Valley to Melbourne 500 kV transmission system does not operate beyond its rated capability. The critical contingency for the LV to Melbourne network is outage of one of the HWTS to SMTS or HWTS to ROTS 500kV lines. This represents the variable costs of additional generation plant. Fixed costs of additional generation plant have not included in this assessment.

Benefit 3. Reduction in active losses valued as fuel cost of the marginal unit as seen by the Victorian region.

Benefit 4. Reduction in shunt capacitors required for supporting the summer peak demand.

3.1.2 Alternative Projects

Under the regulatory test, it is necessary to compare the net present value of the market benefit of a number of alternative projects with different timings and under a variety of market development scenarios. The following transmission augmentation alternatives have been used in this assessment:

1. No transmission augmentations;
2. "Termination Upgrade Option" - upgrade terminations on the existing 3 Latrobe Valley to Melbourne lines operating at 500kV;
3. "Rowville Option" – conversion of the 4th line for 500kV with an additional 1000MVA 500kV/220kV transformer at ROTS;
4. "Cranbourne Option" – conversion of the 4th line for 500kV with an additional 1000MVA 500kV/220kV transformer at Cranbourne; and
5. "5th 500 kV line" – building the 5th 500kV line from Latrobe Valley to Melbourne.

These transmission development alternatives are described in the Technical Report [5].

3.1.3 Market Development Scenarios

The expected net market benefits of the alternative transmission projects have been assessed for a number of market development scenarios. These market development scenarios are as follows:

1. Base case, medium economic growth scenario.
2. Base case, low economic growth scenario.
3. Base case, high economic growth scenario.
4. Development of Basslink in November 2003, medium growth.
5. Development of SNOVIC 800 MW option in November 2004, medium growth.
6. Without the 400 MW SNOVIC project, medium growth.
7. Retirement of 500MW of generation in Latrobe Valley, medium growth.
8. Base case with LRMC bidding strategies, medium growth.
9. Demand side management in Victoria, medium growth.

These market development scenarios would include feasible market developments to the alternative transmission projects, as sources of increased energy efficiency within the power system.

The Base Case relates to the most likely market development scenario over the period of the study. This includes the development of the SNOVIC Upgrade of 400MW by December 2002 and the development of SNI by 2004. Under the base case, the development of Basslink is not considered. Rather, Basslink is considered under market development scenario number 4 above.

The four alternate projects listed in Section 3.1.2 are examined under each scenario.

3.1.4 Project costs

Project costs estimates have been obtained from SPI PowerNet, except for shunt capacitors. Shunt capacitor costs are based on recent experience and the on the excess reactive charging component of TUoS charging in Victoria. Sensitivity studies were carried out with a tolerance of ±12.5%

3.1.5 Project Timing

The earliest commissioning date for termination upgrade option is the financial year 2002/03. The earliest commissioning date for the Rowville option, the Cranbourne option and the 5th 500 kV line option is the financial year 2003/04. Under the regulatory test when maximising the net present value of the market benefit it is also necessary to determine the optimal timing of the upgrade and the alternative projects. Therefore the upgrade and the alternatives are considered with delayed commissioning dates of one or more years to determine the timing that is expected to provide the greatest net present value of the market benefit.

3.2 Benefit assessment

The benefits of the transmission alternatives are assessed using market simulations. This requires the simulation of the market behaviour over the (10 year) study horizon in terms of investment and central dispatch outcomes for each identified market development scenario. The Vision[1] Market Modelling Software has been used to carry out these market simulations. Detail information of the Vision model is presented in Appendix 2 of the Consultation Paper. The market simulations require extensive data as discussed in Section 4.

The hourly generation dispatch and loads for a large number of scenarios to capture the range of variation has been determined using the Vision model. The generation and load information is then used to estimate three of the four transmission augmentation project benefits identified in Section 3.1.1, as follows.

Benefit 1 and 2: These benefits are the reduction in energy that must be curtailed and reduction in additional cost of generation and these have been assessed together. Transmission line loading levels are determined on an hour by hour basis and compared with the line ratings. This allows the load or generation associated with the transmission overloading to be identified. Any generation re-scheduling required has been valued by the price difference of the generators involved in re-scheduling. Any load shedding has been valued at Value of Loss Load (VoLL) price. A flow chart of this process is shown in Figure 3.1.

Benefit 3: This relates to the reduction in energy loss and has been assessed using the PSS/E[2] power transmission network simulation software to solve a load flow case for every hour for each of the transmission alternatives considered. These load flow cases have been optimised to maintain a consistent voltage profile across all transmission alternatives considered. Transmission losses have been valued using System Marginal Price (SMP) for the Victorian region on hourly basis. Loss calculation method is described in Section 3.2.1.

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[1] Vision is a multi-region generation bidding model, designed for use in the National Electricity Market in South-Eastern Australia by VENCorp.

[2] PSS/E is power system analysis software by Power Technology Inc., USA

Benefit 4: This benefit is the reduction in the amount of reactive support required within the Victorian transmission network. As the amount of reactive support required depends on the reactive losses on the transmission network between the Latrobe Valley to the Melbourne area, this requirement is changed as a result of the alternative transmission developments. The reactive support (shunt capacitors) required for each transmission alternative has been estimated using the 10% forecast summer peak demand in Victoria. The reduction in shunt capacitors is valued at the reactive charging rate applied in Victoria.

Reduction in energy curtailed and additional cost of generation

Figure 3.2 shows the flow chart used in assessing the reduction in energy that must be curtailed and reduction in additional cost of generation (Benefits 1 and 2 above).

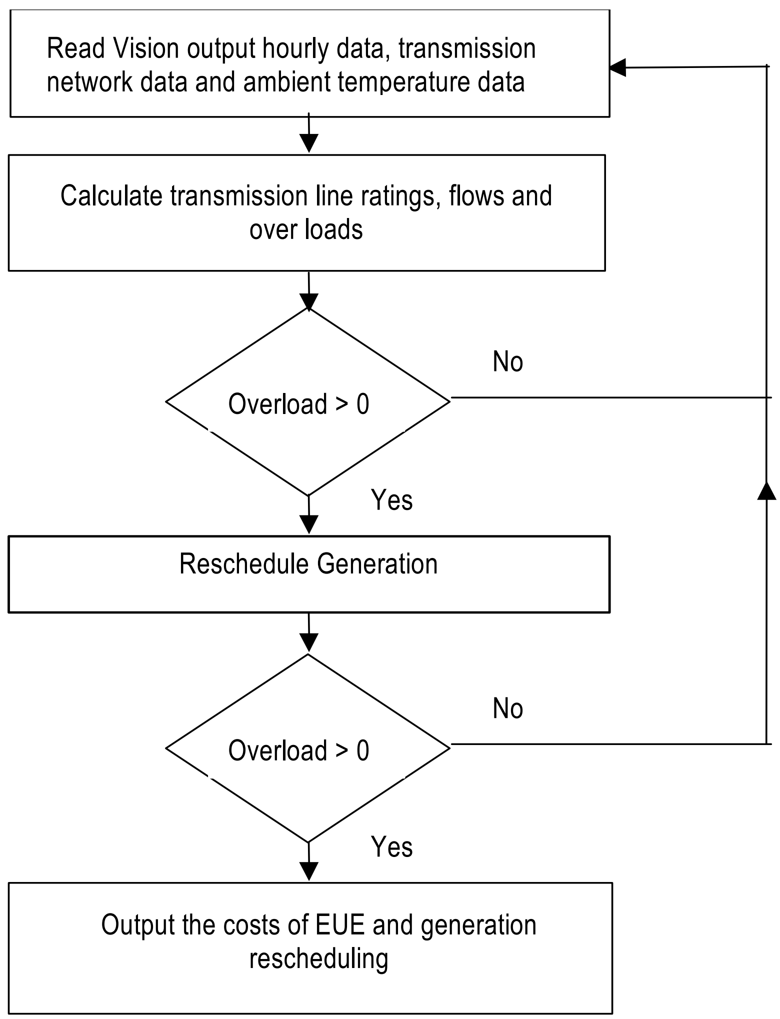

Figure 3.2: Flow chart for assessment of reduction in energy that must be curtailed and reduction in additional cost of generation.

3.2.1 Calculation of Transmission System Loss reduction

The loss calculation process was based on an hour by hour calculation of transmission losses using a full Victorian system loadflow. The approach was to take a loadflow base case (with no transmission augmentation as described in Section 3.1.2), set the generation and load to known levels and record the transmission system losses. Then from an identical loadflow case, which contained the transmission augmentation alternative of interest with the same generation and loading, the transmission system losses were again recorded. The difference between these two values of transmission system losses was the benefit produced by the augmentation for that single set of generation and load levels.

This process was repeated for each of 8760 hours in a simulation year, using generation, load and interstate transfer data provided by the Vision market modelling software. This produced 8760 hourly values for the loss reduction. These values were then multiplied by the hourly SMP (for the Victorian region) given by the Vision simulations, and the sum of these 8760 values gave the benefits of the loss reduction. This approach assumes that the reduced transmission losses are valued at the fuel cost of the marginal unit, which is a reasonable assumption as these MW losses would otherwise be supplied by the marginal, price setting generator.

In order to minimise variations in these loss calculations due to fluctuation in the transmission system voltage profile, an optimal power flow module within the PSS/E loadflow package was used to provide a consistent voltage profile, based on the objective of minimising transmission losses. This was found to be important when comparing transmission losses between different loadflow cases, as the differences in losses were often small compared to the total losses.

3.2.2 Net Present Value (NPV)

The NPV incremental cost of meeting the forecast demand for electricity over the 10 year study horizon is determined for the transmission projects (shown in Section 3.1.2) for each market scenario (shown in Section 3.1.3).

The NPV incremental costs of each market scenario are compared, and the transmission projects that produces the lowest NPV incremental cost have been identified as the option that best satisfies the regulatory test. This decision signal has been tested against variations in the following key parameters:

- discount rate;
- project costs;
- forced outage rates; and
- Carbon tax.

3.3 Market Simulations

Energy market simulations were performed for each of the 10 financial years 2002/03 to 2011/12 using VENCorp's Vision market model. For each of the nine different market development scenarios examined 100 simulation were produced by Vision for each financial year, for each of the 10%, 50% and 90% levels of peak demand (300 in total for each financial year).

The benefits of reduction in energy that must be curtailed and reduction in additional cost of generation assessment process used data from these Vision simulations about the hourly

Victorian generator outputs, interstate transfer levels, Victorian load and generator bid prices. All 300 simulation runs were included in this assessment.

The loss benefit assessment process used data from these Vision simulations about the hourly Victorian generator outputs, Victorian SMP, interstate transfer levels and Victorian load. For the purposes of loss reduction assessment only data from the 10% demand forecasts simulations was used, as the loss benefits associated with a simulation year with lower peak demands does not vary significantly from the 10% demand case.

In the 50% and 90% peak demand cases the total amount of energy delivered over the year was the same, and only the level of demand on the peak demand days was different between the 10%, 50% and 90% market simulations.

For each of the financial year where the loss benefits were calculated three different Vision simulation outputs were selected from the 100 available from the each year, and the results produced from the loss benefit analysis process were averaged.

3.3.1 Generator Data

The generators in each region of the NEM are represented with:

- the number of units and capacity;
- the short run marginal cost (SRMC), or the long run marginal cost (LRMC) depending on the market scenario;
- marginal loss factor (MLF);
- forced outage rate plus repair times after failure; and
- the generator maintenance schedule.

3.3.2 Application of Marginal Loss Factors in Market Modelling

Transferring electricity from one location to another cause transmission losses that must be included in the generator dispatch. The price effect of transmission losses is included in the NEM dispatch engine and in market simulations as dynamic marginal loss factors (MLF) for inter-regional losses and static MLF for intra-regional losses.

MLF values published in NEMMCO web site to be used for the financial year 2001/02 have been used in the assessment. These MLF have been prepared with the 4th 500 kV line from Latrobe Valley to Melbourne operating at 220 kV. The change in MLF that result from conversion of the 4th 500 kV line for 500 kV operation is relatively small and unlikely to alter the generation dispatch with and without the line conversion.

3.3.3 Treatment of Load Temperature Dependence

In a given future year the peak demand will depend to a significant extent on the temperature profile for that year. The NEMMCO 2001 Statement of Opportunities (SOO) [1] and the SOO Addendum Number 1 [2] in June 2001 provide maximum demand forecasts for 10, 50 and 90% probabilities of exceedance temperatures for each jurisdiction. Historical annual load traces are selected that have typical shapes for years with maximum temperatures that correspond to these 10, 50 and 90 % probabilities of exceedance.

For the dispatch simulation for future years the historic load traces are scaled to match the forecast demands and energies while preserving the general shape. Market simulations are performed using 10, 50 and 90 % load traces to capture the range of possible outcomes. The results from these simulations are combined using the weighting factors in Table 3.1.

Load Trace	Weighting Factors
10 %	16.7 %
50 %	66.6 %
90 %	16.7 %

Table 3.1: Temperature Dependence Weighting Factors

Since Victoria and South Australia have approximately coincident peak demands the same base years will be selected for both regions. The demand and energy forecasts for medium, low and high economic growth rates are treated as separate scenarios.

3.4 Generation Expansion

The additional generation capacity which was added to the system to support demand growth is described in this section.

3.4.1 Committed and Anticipated Projects

Projects that are committed are included in all market simulations and in the determination of the benefits. The anticipated projects are included as scenarios in the market simulations and in the determination of the benefits.

The Regulatory Test defines;

- committed projects as "projects the implementation and construction of which have commenced and witch have expected commissioning dates within three years", and
- anticipated projects as "projects the implementation and construction of which have commenced and witch have expected commissioning dates within three years".

Once all committed and anticipated projects have been included in a given scenario then additional modelled generation needs to be considered with additional demand growth. The regulatory test identifies two types of generation entry, namely market driven and reliability driven entry.

3.4.2 Generation Entry

Market Driven Entry

The entry of market driven generators are based on there being a sufficient premium (ie income above the SRMC derived from the spot market) to support a market driven generator in the relevant region.

Reliability Driven Entry

The entry of reliability driven generators are to satisfy the reliability targets as defined by the NECA Reliability Panel and stated in the SOO [1]. Table 3.2 shows the reserve levels for each of the regions.

Region	QLD	NSW	Victoria	SA
Reserve Trigger Levels	420 MW	660 MW	500 MW	260 MW

Table 3.2: Minimum Reserve Levels required for each Region to satisfy the reliability criteria

In any given year, market driven entry does not provide sufficient generation to meet the reliability standards. Therefore, capacity has been expanded to the reliability entry level by adding new generators.

The criteria for assessing the size and location of reliability entry are;

- sufficient additional reliability generation is required to maintain sufficient reserve margin in each region;
- the interconnectors must remain within their limits as defined by the constraints in Section 4.2; and
- the 10 % POE load traces define the level of coincidence between maximum demands in the regions.

Additional plant is to be offered in to the market at SRMC for all market scenarios except for the LRMC case. VENCorp considers this biding strategy adequately represents the behaviour of market participants for the Latrobe Valley to Melbourne transmission augmentations.

3.4.3 Modelling Issues for New Generators

New generators under Section 3.4.2 are assumed to be Open Cycle Gas Turbines (OCGT) and these generators are modelled with zero forced outage rate.

3.4.4 Plant Mothballing and Retirement

Where plant owners are committed to withdraw or reinstate, for whatever reason, will be incorporated into all market simulations and in the determination of the benefits. Where no commitment has been made but there is evidence that there is likely to be withdrawn or reinstate then this will be included as a scenario in the market simulations.

3.5 Duration of Simulations and End Effects

Simulation data including demand forecasts and transmission network information are available for a ten-year outlook. Accuracy of data and network information beyond this horizon is considered uncertain. Therefore, the duration of this evaluation is set as ten years. End effects beyond this period were not included in the assessment.

3.6 Inter-Regional Constraints

Inter-regional constraints have been included as static limits and shown in Section 4.2.

3.7 Exclusions

3.7.1 Inter-regional impacts

It is expected that any inter-regional impacts of the project are beneficial to the market as a whole, however these impacts are not material. Inter-regional impacts are therefore excluded from the economic evaluation of net benefits.

3.7.2 Bush fires

As described in the Technical Report [5], there is a chance for a bush fire to force two Latrobe Valley to Melbourne 500 kV lines to be out of service simultaneously on a hot summer day. Although the amount of load shedding for such an event is large, probability of experiencing an event is very small. Therefore, reliability improvement during bush fires is not included as a benefit to transmission augmentations.

4 ASSUMPTIONS AND SIMULATION DATA

The assumptions and simulation data used in the Vision market simulation model are described in this section.

4.1 Generator Data

4.1.1 Committed projects

Existing and committed generation plant is consistent with that stated in the 2001 NEMMCO SOO Addendum 2 [3]. Generation capability is on "at generator terminals" basis. All the generator capacities in the NEM used in the market simulations can be found in Table 1 in Appendix 3.

4.1.2 Additional Generation Assumptions

The study assumes that all new generating capacity required for maintaining the minimum level of reserve determined by the NECA Reliability Panel will be open cycle gas turbines. Minimum increments of 100 MW are assumed. A capital cost of $400 per kW, and an asset life of 30 years are assumed. It should be noted that given recent experience, this value may be on the low side and values of $500 to $600 per kW may be more typical.

The level of new generation capacity required for the Victorian system is shown in Figure 4.1 and Figure 4.2 (and in Appendix 2) for the nine market scenarios considered.

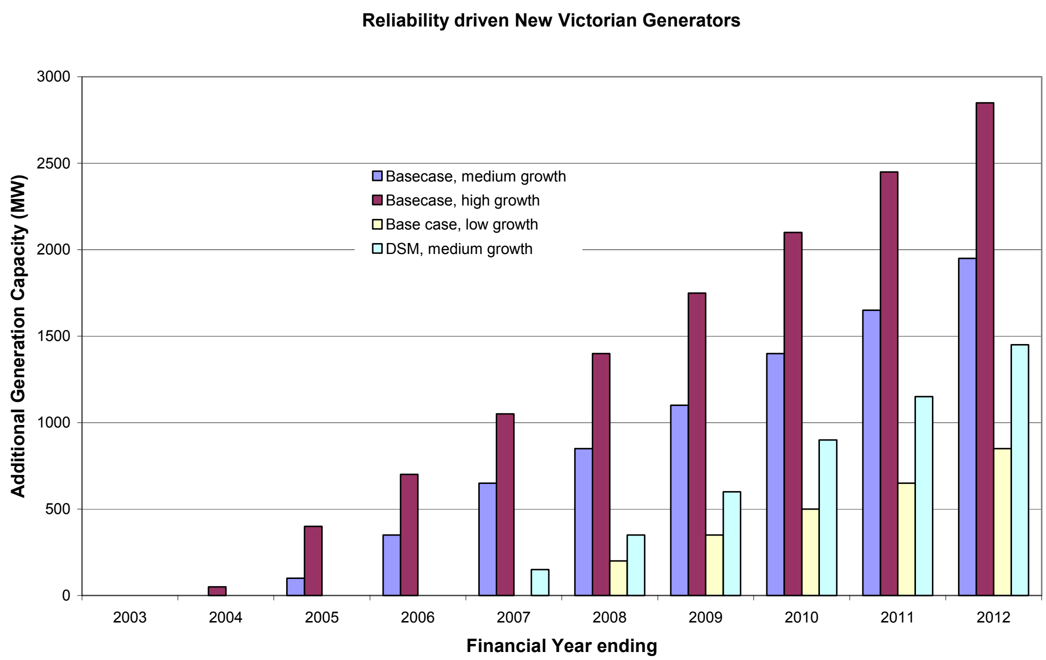

Figure 4.1: Reliability driven new Victorian generator additions

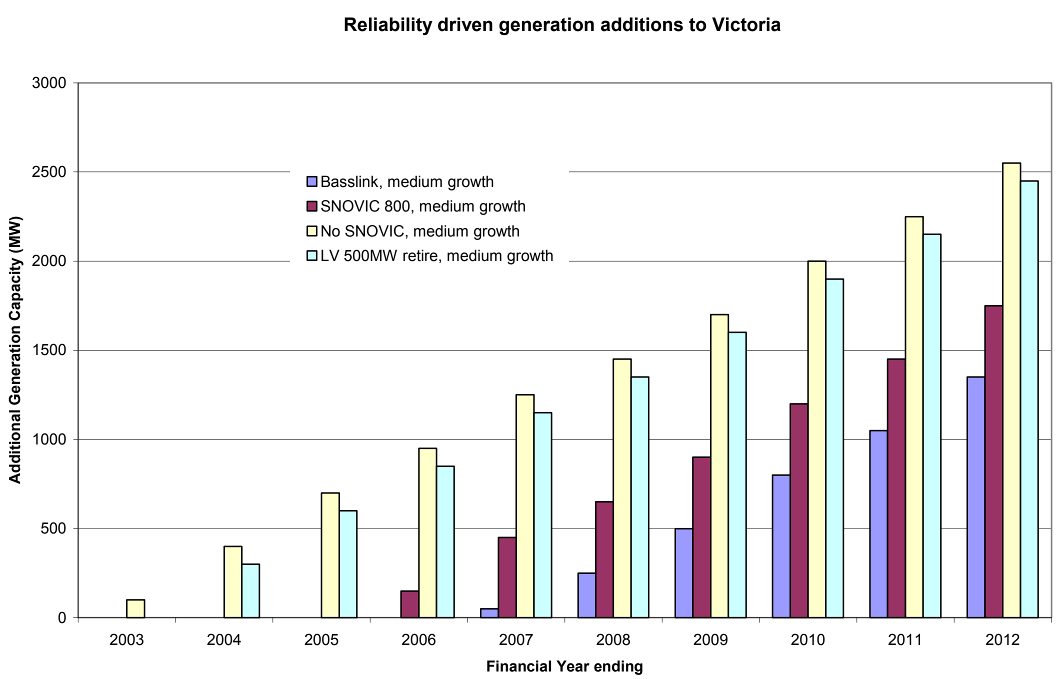

Figure 4.2: Reliability driven new Victorian generator additions

It is assumed that 50% of the additional generation in Victorian region to be located in the Latrobe Valley area and connected to the 500 kV network. Rest of the additional generation to be connected on western side of the Latrobe Valley to Melbourne 500 kV lines. Apart from the required generation shown in Victoria in Figs 4.1 and 4.2, incremental generation capacity required for all the market development scenarios for Victoria and South Australia can be found in Tables A2.1 and A2.2 in Appendix 2.

4.1.3 Generator Short Run Marginal Costs (SRMC)

Short run marginal cost (SRMC) bidding is assumed, in accordance with the latest SNI Stage 1 report [6]. This approach enables reasonable estimates to be made of the total resource cost of energy dispatch for each scenario. This approach is consistent with the requirements of the ACCC regulatory test. SRMC can be found in Table A3.1 in Appendix 3.

4.1.4 Generator Long Run Marginal Costs (LRMC)

Long run marginal cost (LRMC) bidding is assumed, in accordance with the latest SNI Stage 1 report [5]. This approach enables reasonable an estimate to be made of the base generation shift from Latrobe Valley to western side of the Latrobe Valley to Melbourne 500 kV lines. LRMC can be found in Table A3.1 in Appendix 3.

4.1.5 Generator Forced Outage Rates

Generator forced outage rates and outage times are consistent with those stated in the latest SNI Stage 1 report [6]. Generation Forced Outage Rates can be found in Table A3.1 in Appendix 3.

4.1.6 Generator Maintenance

Notional periodic maintenance assumptions are consistent with those used in VENCorp's 2001 Annual Planning Review studies [4]. Generator maintenance schedules can be found in Table A3.2 in Appendix 3.

4.1.7 Snowy and Southern Hydro

Snowy is modelled as generation in the Snowy region with an annual energy target of 4800 GWh. The monthly profile used is consistent with that applied in the SNI Stage 1 report [6].

Southern Hydro is modelled as generation in the Victorian region with a total annual energy target of 970 GWh and consistent with those used in VENCorp's 2001 Annual Planning Review studies [4]. The monthly profile to reflect typical inflow and/or irrigation releases.

4.2 Inter regional Transfer Capabilities

The regions modelled are: Queensland, NSW, Snowy, Victoria, South Australia and Tasmania. Inter regional transfer capabilities used in the base case are shown in Table 4.1.

Regions		Capability (MW)
From	To	
VIC	SA	700[3]
SA	VIC	450[4]
SNOWY	VIC	2100[5]
VIC	SNOWY	1100
SNOWY	NSW	3000 (Winter), 2500 (Summer)
NSW	SNOWY	850
NSW	QLD	500
QLD	NSW	1000

Table 4.1: Nominal Inter-Regional Transfer Capabilities

Basslink is modelled as a market scenario with Victorian import capability of 600 MW and Victorian export capability of 400 MW.

4.3 Demand and Energy Forecast

Demand traces used in VENCorp's 2001 Annual Planning Review (APR), modified for coincident 10% reference years in Victoria and South Australia, are available. Demand and generation data is expressed on "at generator terminals" basis. Assumed energy growth reflects the Medium energy growth forecast. Maximum demand forecasts having probabilities of exceedance of 10%, 50% and 90% have been used. Separate simulation runs are made for each demand trace. Post-processing is used to obtain composite reliability outputs use the same weighting as those used in the Reliability Panel reserve requirement studies.

4.4 Load shedding

To reflect the ACCC determination of December 2000, expected unserved energy (involuntary load shedding due to insufficient capacity) is valued at the VoLL wholesale market price cap ($5,000/MWh for fiscal 2001/02, and $10,000/MWh thereafter).

4.5 Generation re-scheduling

Generation rescheduling is valued as the differential cost of dispatching higher cost fuel generators in place of low cost fuel generation to avoid transmission overloads. Generation rescheduling cost is always lower than the load shedding option and therefore, considered for transmission line load reduction as the first option.

4.6 Number of simulations

Number of simulations generated for forecast demand levels are;

- 100 simulations with 10% demand
- 100 simulations with 50% demand
- 100 simulations with 90% demand

[3] Combined effect of SNI, MurrayLink and the existing Victoria to South Australian link.

[4] Combined effect of SNI, MurrayLink and the existing Victoria to South Australian link.

[5] Includes combined capability of SNOVIC project and SNI project.

Energy at risk and generation rescheduling has been estimated using all these simulations. Transmission loss savings estimated using three simulations from the 10% demand trace. There is no significant difference in loss savings with probability of demand exceedance level.

4.7 Study period

The study period is 10 years, from fiscal 2002/03 to 2011/12. Incremental transmission capital costs are incorporated as annuities, to ensure that results obtained for this shortened study horizon are not distorted by cash flow effects associated with long-lived capital expenditures.

4.8 Transmission loss

4.8.1 System losses

The latest NEMMCO dynamic loss factor equations and static loss factors are used. Details are available at: http://www.nemmco.com.au/operating/transmission/

4.8.2 Loss savings from transmission augmentations

Transmission loss change due to a transmission augmentation is valued as SMP of the Victorian region (or fuel cost saving with SRMC bidding). This value reflects combined benefits to the market participants (generators and consumers) as a result of reduced transmission loss.

Transmission loss saving is about 10 MW average for the three transmission augmentations; Rowville option, Cranbourne option and 5th line option. This is equivalent to a 10 MW green house friendly generator with a 100% plant factor. Avoided capital cost of this generation was not considered in the assessment.

Reduction in transmission loss by a transmission augmentation reduces the amount of generation required otherwise. This reduces the amount of CO_2 emission. The amount of CO_2 emission is estimated using the 1.01 t CO_2e/MWh (average for the first six months of year 2001). Value of CO_2 emission is discussed in Section 4.14.

4.9 Reactive support

Avoided shunt capacitors by the transmission augmentations have been considered as a project benefit as described in Section 3.2. These capacitors are valued as value of reactive charging applied in Victoria.

4.10 Ancillary service

There is no significant change to ancillary services due to the transmission projects.

4.11 Transmission development plan

The Base Case transmission development is as planned as at 1 December 2001, including DirectLink, MurrayLink, SNOVIC and SNI. Transmission capabilities for QNI are 500 MW North and 1000 MW South. Basslink and SNOVIC 800 are included as a market development scenarios.

A list of the other augmentations made to the Victorian transmission system each year is given below. All transmission augmentations listed below not associated with this project are consistent with the 10-year development scenarios outlined in VENCorp's Electricity Annual Planning Review 2001 [4].

- The 2004/05 loadflow case had 150 MVAr capacitor banks added at Geelong and West Melbourne. A 500/220 kV transformer was installed at Cranbourne in the do-nothing case and the 5th line case to support forecasts load growth in the eastern metropolitan area. A 2nd 500/220 kV transformer was installed at Moorabool in all three loadflow cases. A 4th 330/220 kV transformer was installed at Dederang in all three loadflow cases
- The 2005/06 loadflow case had 150 MVAr capacitor banks installed at Richmond and Keilor No. 2 220 kV bus. A 500/220 kV transformer was installed at Cranbourne in the 4th 500 kV line case.
- The 2006/07 loadflow cases had150 MVAr capacitor banks installed at Springvale and Keilor No 1&3 220 kV. A third Moorabool to Ballarat 220 kV line was added to all three cases.
- The 2007/08 loadflow cases had 150 MVAr capacitor banks installed at Dederang 220 kV and Thomastown No. 2 220 kV bus.
- The 2008/09 loadflow cases had 150 MVAr capacitor banks installed at Brunswick and Rowville No.1/2 220 kV bus
- The 2009/10 loadflow cases had 150 MVAr capacitor banks installed at Thomastown Bus 1 and Newport 220 kV
- The 2010/11 loadflow cases had 150 MVAr capacitor banks installed at Shepparton and Terang 220 kV
- The 2011/12 loadflow cases had 150 MVAr capacitor banks installed at South Morang 330 kV and Brooklyn 220 kV

4.12 Transmission project costs

Capital, operation and maintenance costs of alternative transmission projects are shown in Table 4.2. Operating and maintenance costs are based on assumption of 20% of the capital works involving additional transmission developments. There is no additional maintenance and operating cost for existing plant upgrade or replacement. Details of these cost estimates are shown in the accompanying Technical report [5].

Costs	Rowville Option	Cranbourne Option	Termination upgrade	5th 500 kV line
Capital cost $M	23.8	35.8	2.6	71
Operation and maintenance $M	4.0	6.7	0.0	14

Table 4.2: Costs of alternative transmission projects

Costs of shunt capacitors are valued as excess reactive charging rates of $2250 per MVAr per year.

4.13 Interest rates

Discount rates of 8%, 10% and 12% real has been applied.

4.14 Externalities: Greenhouse gas reduction

In May 1999, the Commonwealth Government committed an additional $400 million over four years, through the Greenhouse Gas Abatement Program (GGAP) to further assist Australia in meeting its commitments under the Kyoto Protocol. The objective of the program is to reduce Australia's net greenhouse gas emissions by supporting activities that are likely to result in substantial emission reductions.

One factor that is not incorporated into the economic decision signal provided by the regulatory test is the benefit delivered by the project in terms of greenhouse gas reduction. The project is expected to reduce transmission losses by around 90 GWh per year (10 MW average at 100% capacity factor) in the year 2004, and increases to around 150 GWh per year by the year 2012. This equates to a reduction in $C0_2$ emissions of roughly 90,000 and 150,000 tonnes per year for the years 2004 and 2012 respectively.

The potential value of carbon credits in an emission trading market has been estimated to be in the range of $10 to $50 per tonne.[6] Taking the lower bound of this range, the intangible value of the greenhouse gas emission reductions that would be delivered by the project is $1 million per year.

Projects that have received funding under the Commonwealth Government's Greenhouse Gas Abatement Program provide a more tangible measure of the value of emission reductions. Successful projects include the following:

Applicant	Project	Grant	Emission reduction	Implied value of $C0_2$ reductions
Macquarie Generation	Replacement of ageing low pressure turbines at Liddell power station	$5 million towards total cost of $52 million	1.5 MT over 5 years	$3.30 per tonne
Queensland Alumina Limited	Replacement of natural gas fired kilns, with energy efficient stationary calciners	$11 million towards total cost of $175 million	1.5 MT over 5 years	$7.30 per tonne
Nabalco Pty Ltd	Conversion of fuel from oil to natural gas	$7 million towards total cost of $48 million	1.2 MT over 5 years	$5.80 per tonne
Origin Energy and the Australian Ecogeneration Association	Development of cogeneration plants	$26 million	More than 3 MT over 5 years	Not more than $8.70 per tonne

Table 4.3: Projects that have received funding under the Commonwealth Government's Greenhouse Gas Abatement Program

It is noteworthy that the Greenhouse Gas Abatement Program (GGAP) has contributed funding to greenhouse friendly power generation projects proposed by private and State-owned

6 Refer to the document Questions and answers: Carbon trading - Emissions trading and carbon credits at the website of the Australian Greenhouse Office on the following address: http://www.greenhouse.gov.au/emissionstrading/qanda.html

generation companies. These projects are described by the Australian Greenhouse Office as "innovative", and in the case of Macquarie Generation, the project is described as "beyond commercial best practice". This suggests that the GGAP funding has been provided only to the extent required to move a project from being marginally uneconomic to economic. It may therefore be possible for VENCorp to seek funding for the project, to the extent that the direct benefits of the project fall short of covering its costs.

5 Net Benefits

5.1 Market benefit analysis

The costs of each transmission alternative have been obtained from the best possible source in providing cost estimates, on a common basis for alternative project comparison.

A cost benefit assessment has been carried out consisting the costs and benefits for each component in each year of the ten-year study period. The four types of benefits that are included in the assessment are discussed in Sections 5.1.1 to 5.1.4.

5.1.1 Generation re-scheduling benefits

This benefit arises from reducing transmission constraint between the Latrobe Valley and the Melbourne area, as low cost brown coal generators in Latrobe Valley would not be able to supply loads. The alternative generating sources to replace Latrobe Valley generators available are: gas fired generators, Victorian hydro generators or generators from other states. The benefits of generation re-scheduling has been included in each of the ten years of the study.

5.1.2 Expected unserved energy (EUE) benefits

This benefit arises from reducing transmission constraint between the Latrobe Valley and the Melbourne area, when the generation re-scheduling options described in Section 5.1.1 has been completed. EUE calculation process has been described in Section 0. Load shed in Victoria is valued at the price of VoLL. A sensitivity study has been carried out with load shedding valued at twice the price of VoLL. The benefits relating to EUE has been included in each of the ten years of the study.

5.1.3 Transmission loss reduction benefits

This benefit arises from the reduced transmission losses as a result of the different power flow distribution and voltage levels of alternative transmission projects. The transmission loss change due to the transmission augmentation is valued as fuel cost of the marginal unit as seen by the Victorian region. This value reflects combined benefits to the market participants (generators and consumers) as a result of reduced transmission losses. Transmission loss savings have been included for each of the ten years of the study.

A typical set of transmission loss saving results is shown in Figure 5.1. The plot shows the difference in hourly losses over 1 simulation year between 2 loadflows, one of which contained the 4^{th} 500 kV line and a 500/220 kV transformer at Rowville, and the other which did not. The modelling data used for this simulation was from 2011/12, high economic growth scenario. In this scenario, the average losses were reduced by approximately 10.1 MW/hr, with a value of approximately $4.7 million.

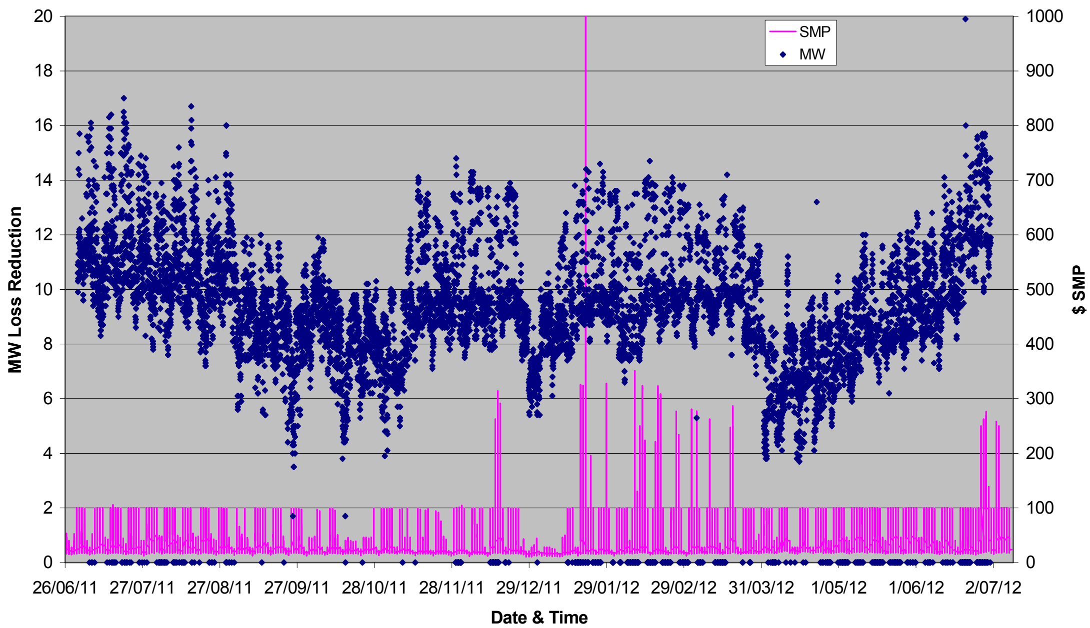

Figure 5.1: Loss savings for the year 2011/2012 for the Rowville option

For each financial year three different simulation years worth of VISION data were used to assess the benefits of a transmission augmentation. The results were then averaged to produce the final result. There was normally little variation between the three individual results.

5.1.4 Reactive support benefits

Additional shunt capacitors are being installed annually in Victoria to support the summer peak demand. It is possible to avoid installation of part of these capacitors by augmenting the transmission network. Benefits of these avoided capacitors have been included for each of the ten years of the study.

5.1.5 Transmission costs

Annual costs of capital works and associated operating and maintenance costs have been included.

5.1.6 Additional reliability benefits of Cranbourne option

The Cranbourne option increases security of supply to East Rowville and Tyabb terminal stations as described in the Technical Report [5]. These two terminal stations are supplied from Rowville terminal Station using a double circuits tower line.

The increase in reliability of supply to East Rowville and Tyabb with the Cranbourne option is shown in Table 5.1. These benefits have been included in the economic assessment in addition to higher loss benefits for Cranbourne option. Details of supply reliability assessment to East Rowville and Tyabb terminal stations are shown in the Technical Report [5].

Financial Year Ending	Expected Unserved Energy (EUE) at ERTS and TBTS	
	MWhr	$M
2002	31.00	0.31
2003	32.41	0.32
2004	34.01	0.34
2005	35.84	0.36
2006	38.25	0.38
2007	41.15	0.41
2008	45.01	0.45
2009	49.53	0.50
2010	55.18	0.55
2011	61.90	0.62
2012	69.52	0.70

Table 5.1: Increase in reliability of supply to East Rowville and Tyabb electricity supply with Cranbourne option.

5.1.7 Benefits of Other Options

The discussion above has focused on the cost and benefits of the four transmissions network alternative projects. The 500kV line upgrade projects contribute benefits in terms of expected unserved energy, generation re-scheduling, transmission losses and reduction in reactive support. The non-network alternatives, which were identified in the Technical Report [5], are also examined for their benefits and costs.

Demand side management developments in the Melbourne metropolitan area will tend to reduce the energy at risk from load shedding and the need for additional reactive support. However, DSM will not significantly impact on the rescheduling costs in the event of an outage on one of the 500kV lines. In the economic assessment, DSM has been valued at a level above the most expensive generation in the system (but below VoLL). As DSM is also available for brief periods at high price, it will not have any impact on the transmission losses associated with the project.

As discussed in the Technical Report [5], the other non-network alternative is a different generation development schedule. The impact of different generation allocation will mainly be on the transmission losses. If generation developments occur outside of the Latrobe Valley, the transmission losses on the Latrobe Valley to Melbourne corridor will be reduced. This reduction in losses will only be significant (ie approach that of the benefit afforded by the 4^{th} 500kV line) if the generation has a capacity factor approaching 100%. This change in generation would need to be of the order of at least 300MW to produce the reduction in losses of 10MW which is observed with the 4^{th} 500kV line upgrade. The costs associated with such an alternative would depend on both the capital and operating costs of such an option.

The analysis of the costs and benefits of these alternatives are discussed in Section 5.3.

5.2 Results

Summary of results of the net benefit test[7] is shown in Table 5.2 to Table 5.7. The values shown in these tables are NPV of benefits minus NPV of costs for the ten-year study period. A higher number indicates higher benefits to the National Electricity Market. Details of the net benefit assessment are shown in Appendix 4.

5.2.1 Market development scenarios

Market scenario	Base case Growth	Base case-Growth	Base case-Growth	Basslink	SNOVIC 800	NO SNOVIC	Retire LV 500 MW	LRMC	DM in Victoria
Load growth	Medium	Low	High	Medium	Medium	Medium	Medium	Medium	Medium
Termination upgrade	4.6	3.5	7.4	4.2	4.5	7.0	0.9	1.9	4.2
Rowville option	**7.5**	**4.6**	**16.5**	**6.9**	**7.5**	**10.2**	**2.9**	**14.7**	**7.1**
Cranbourne option	2.9	1.0	11.8	2.2	2.8	5.5	-1.8	10.0	2.5
5th 500 kV line	-20.1	-26.0	-13.4	-22.9	-22.9	-20.3	-27.7	-15.3	-23.3

Table 5.2: Net Benefits of alternative transmission projects with 8% discount rate

Market scenario	Base case Growth	Base case-Growth	Base case-Growth	Basslink	SNOVIC 800	NO SNOVIC	Retire LV 500 MW	LRMC	DM in Victoria
Load growth	Medium	Low	High	Medium	Medium	Medium	Medium	Medium	Medium
Termination upgrade	3.8	**2.9**	6.2	3.4	3.8	5.9	**0.5**	1.4	3.4
Rowville option	**4.1**	1.5	**11.8**	**3.5**	**4.1**	**6.4**	-0.05	**10.5**	**3.7**
Cranbourne option	1.1	-3.0	6.2	-2.1	-1.5	0.8	-5.6	4.9	-1.8
5th 500 kV line	-26.1	-30.7	-19.9	-28.9	-28.0	-25.7	-32.4	-21.3	-28.4

Table 5.3: Net Benefits of alternative transmission projects with 10% discount rate

7 It should be noted that the establishment cost for Cranbourne will depend on whether or not it becomes a connection point to the transmission system at or about the same time ie a 220/66 kV transformation station is established. This would reduce the cost of making the 500 kV connection at Cranbourne as about $9M of the works is common to both projects. The benefits that are shown in Table 5.2 to Table 5.7 have been assessed assuming the full costs are against the 500 kV development. This represents a worst case outcome for the Cranbourne option. Table 5.10 to Table 5.11 indicate how the benefits of the Cranbourne option improve as the cost of establishing the 500 kV connection is reduced. Section 5.5 further discusses the Cranbourne option and the additional benefits it provides compared to the Rowville option.

Market scenario	Base case Growth	Base case-Growth	Base case-Growth	Basslink	SNOVIC 800	NO SNOVIC	Retire LV 500 MW	LRMC	DM in Victoria
Load growth	Medium	Low	High	Medium	Medium	Medium	Medium	Medium	Medium
Termination upgrade	5.5	4.2	8.8	5.1	5.4	8.2	1.4	2.6	5.0
Rowville option	**11.5**	**8.1**	**21.9**	**10.8**	**11.5**	**14.5**	**6.3**	**19.6**	**11.0**
Cranbourne option	6.2	5.7	18.3	7.1	7.8	10.9	2.7	16.0	7.4
5th 500 kV line	-13.2	-20.5	-6.0	-18.0	-17.0	-14.0	-22.4	-8.3	-17.5

Table 5.4: Net Benefits of alternative transmission projects with 6% discount rate

5.2.2 Sensitivity studies

Tables 6.5 to 6.7 show the results of the sensitivity studies that were carried out.

Scenario	VoLL change to $20K	Project cost increase by 12.5%	Project cost reduce by 12.5%	Double FOR	Carbon tax	ROTS increase by 12.5% & CBTS reduce by 12.5%
Load growth	Medium	Medium	Medium	Medium	Medium	Medium
Termination upgrade	6.8	4.4	4.8	10.7	4.6	4.6
Rowville option	11.1	**5.9**	**9.1**	**13.9**	**12.0**	5.9
Cranbourne option	**12.1**	3.1	5.3	11.9	7.3	**5.3**
5th 500 kV line	-16.3	-25.0	-15.3	-13.7	-14.8	-20.1

Table 5.5: Net Benefits of alternative transmission projects with 8% discount rate

Scenario	VoLL change to $20K	Project cost increase by 12.5%	Project cost reduce by 12.5%	Double FOR	Carbon tax	ROTS increase by 12.5% & CBTS reduce by 12.5%
Load growth	Medium	Medium	Medium	Medium	Medium	Medium
Termination upgrade	5.8	**3.6**	4.0	9.3	3.8	3.8
Rowville option	7.7	2.3	**5.8**	**9.7**	**8.1**	**2.3**
Cranbourne option	**8.2**	-1.3	1.1	7.0	2.6	1.1
5th 500 kV line	-23.2	-31.3	-20.9	-20.5	-21.3	-26.1

Table 5.6: Net Benefits of alternative transmission projects with 10% discount rate

Scenario	VoLL change to $20K	Project cost increase by 12.5%	Project cost reduce by 12.5%	Double FOR	Carbon tax	ROTS increase by 12.5% & CBTS reduce by 12.5%
Load growth	Medium	Medium	Medium	Medium	Medium	Medium
Termination upgrade	8.0	5.3	5.7	12.4	5.5	5.5
Rowville option	15.1	**10.1**	**13.0**	**18.8**	**16.5**	10.1
Cranbourne option	**16.7**	8.1	10.1	17.5	12.9	**10.1**
5th 500 kV line	-8.7	-17.6	-8.8	-6.0	-7.3	-13.2

Table 5.7: Net Benefits of alternative transmission projects with 6% discount rate

5.3 Analysis of results

5.3.1 Components of benefits

Benefits for the transmission alternative "the Rowville option" is shown in Figure 5.2 for the base case market scenario.

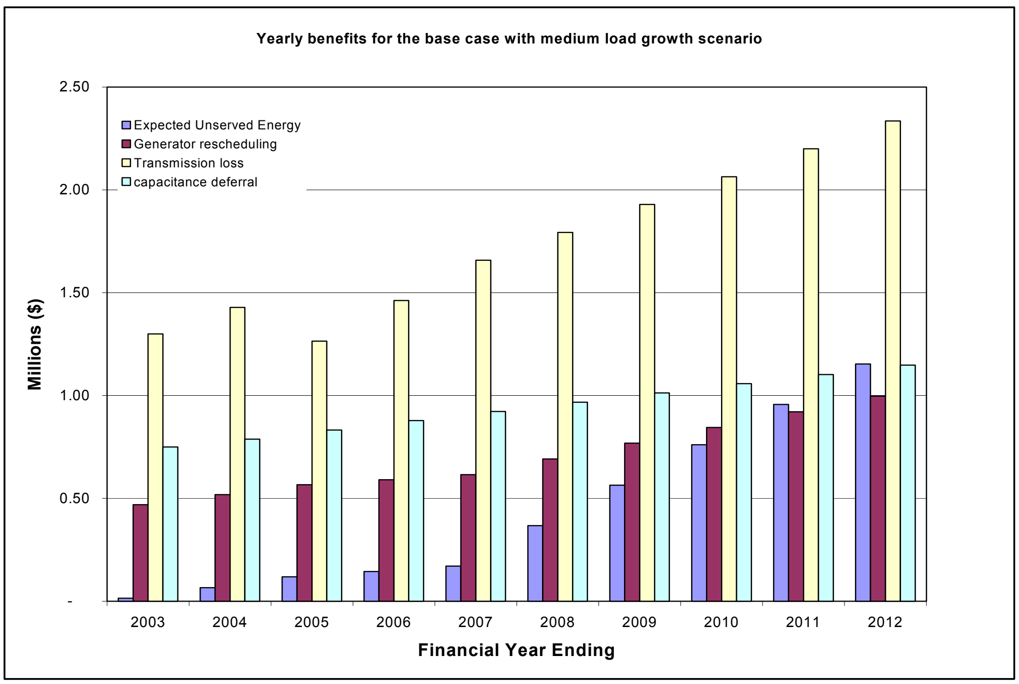

Figure 5.2: Components of Benefits for the Rowville option base case scenario

All four benefits are identified on an annual basis. The total NPV benefit for this base case is $7.5M, as identified in Table 5.2 for a discount rate of 8%. The total present value of these benefits for this base case is $21.8M for a discount rate of 8%. The cost associated with the Rowville Option has a NPV of $14.3M, leading to the net benefit for this option and market development scenario of $7.5M, as shown in Table 5.2.

As can be seen from these results, the annual transmission loss benefit of the project is initially $1.3M in 2002/03, and increasing in step with the growth in load demand over the period of the study to $2.3M in 2011/12. (The slight dip in the transmission loss benefit in 2004/05 is due to one year advancement of the next eastern metropolitan area 500/220 kV transformer, that is included in the base case, without the 500 kV line conversion works).

The value of the expected unserved energy in 2002/03 is only $0.1M in 2002/03, but this increase to over $1M by 2011/12. This is due to the continuing growth in the peak summer demand over the course of the study and consequent increased load, which is exposed to shedding in the event of an outage on one of the 500kV lines.

The value of the rescheduled generation benefit is initially about $0.5M in 2002/03 and this gradually increases to $1.0M by 2011/12. The increase in this benefit is reasonably moderate over the period of the study, in contrast with the rapid increase in the unserved energy.

The final component in the benefit assessment is the reduction in the reactive support requirement as a result of the project. The 4th 500kV line will initially mean that the additional reactive support required in 2002/03 will be reduce by 335 MVAr. This translates to an annualised benefit of $0.75M in 2002/03. This annual benefit increases to $1.15M by 2011/12, in line with the increasing demand over the period.

The details of the benefits for each of the market development scenarios are presented in Appendix 7.

5.3.2 The net benefit test

The Net benefit test states that:

> "A proposed augmentation maximises the market benefit if it achieves a greater market benefit in most (although not all) credible scenarios."

The number of times that each transmission augmentation maximises the market benefits out of the 45 market scenarios considered is shown in Table 5.8.

Scenario	Number of scenarios that maximises the market benefits
Termination upgrade	3
Rowville option	38
Cranbourne option	4
5th 500 kV line	0

Table 5.8: Number of Scenarios that maximises the market benefits

The Rowville option maximises the market benefits in 38 scenarios out of the 45 market scenarios considered and satisfies this criterion of the net benefit test.

In addition, the Net benefit test states that:

> "An augmentation minimises the cost if it achieves a lower cost in most (although not all) credible scenarios."

The number of times that each transmission augmentation minimises the cost out of the 45 market scenarios considered is shown in Table 5.9.

Scenario	Number of scenarios with lower costs than benefits
Termination upgrade	45
Rowville option	44
Cranbourne option	38
5th 500 kV line	0

Table 5.9: Number of Scenarios that maximises the market benefits

Three out of the four transmission options satisfy this criterion of the net benefit test. The Termination upgrade option has a lower cost than benefit for all 45 scenarios considered. The Rowville option is the next with a lower cost than benefits in 44 scenarios out of the 45 scenarios considered. The Cranbourne option is the third with a lower cost than benefits in 38 scenarios out of the 45 scenarios considered.

In summary:

- Rowville option satisfies the net benefit test;
- the line termination upgrade option does not satisfy the net benefit test, as there is an alternative option (Rowville option) that maximises the net benefits; and
- it is not possible to clearly differentiate Cranbourne and Rowville options due to high tolerance of cost estimates and the possibility of a 220/66 kV development at Cranbourne.

5.4 Analysis of sensitivity study results

The results of the sensitivity analysis are presented in Table 5.5 for a discount rate of 8%. Tables 5.6 and 5.7 present the results of the sensitivity studies for 10% and 6% discount rates respectively. As is clear from Table 5.5, the Rowville option provides the maximum net benefit for all but the case where VoLL is increased to $20,000 and where the costs of the Rowville and Cranbourne options are changed. The Cranbourne option delivers marginally higher benefits than the Rowville option if VoLL is increased. However, the relative differences for the variation in VoLL is not significant and does not alter the conclusions with regard to the Rowville option. The sensitivity studies demonstrate the robustness of this option.

5.5 Establishment of a new Cranbourne terminal station

The long term electricity supply plan is to establish a 500/220 kV transformation station at Cranbourne to supply demand around South Gippsland and the Mornington Peninsula areas. The two southern easement 500 kV lines from the Latrobe Valley to Melbourne (including the line operating at 220 kV) pass through the site reserved for the future Cranbourne terminal station.

One option for connection of the 500 kV line into the Melbourne area after it is converted from 220 kV operation is to establish the 500/220 kV transformation at Cranbourne. The cost of transformation, 500 kV and 220 kV switching to connect into the existing ERTS to TBTS 220 kV lines results in this option being about $12M more expensive than the Rowville option. However, TXU and United Energy are contemplating development of a 220/66 kV transformation station at Cranbourne around the same time. The timing of this development is sensitive to other alternatives such as DSM and new generation with about 40 MW of DSM or additional generation giving about a one-year deferment in timing.

The 220/66 kV station will also include the development of a 220 kV switchyard to switch the ERTS to TBTS 220 kV lines. Much of this work is common to both developments and therefore it is more appropriate to consider only part of the cost against the 500/220 kV development. The sensitivity of the overall cost of 500/220 kV development to the timing of the 220/66 kV development is shown in Table 5.10 to Table 5.12.

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Scenario	Avoided cost of CBTS by $9M in 2003/4	Avoided cost of CBTS by $9M in 2004/5	Avoided cost of CBTS by $9M in 2005/6
Load growth	Medium	Medium	Medium
Termination upgrade	4.6	4.6	4.6
Rowville option	**7.5**	**7.5**	**7.5**
Cranbourne option	**7.5**	6.8	6.2
5th 500 kV line	-20.1	-20.1	-20.1

Table 5.10: Net Benefits of projects with Cranbourne 220/66 kV transmission with 8% discount rate

Scenario	Avoided cost of CBTS by $9M in 2003/4	Avoided cost of CBTS by $9M in 2004/5	Avoided cost of CBTS by $9M in 2005/6
Load growth	Medium	Medium	Medium
Termination upgrade	3.8	3.8	3.8
Rowville option	**4.1**	**4.1**	**4.1**
Cranbourne option	3.5	2.7	2.0
5th 500 kV line	-26.1	-26.1	-26.1

Table 5.11: Net Benefits of projects with Cranbourne 220/66 kV transmission with 10% discount rate

Scenario	Avoided cost of CBTS by $9M in 2003/4	Avoided cost of CBTS by $9M in 2004/5	Avoided cost of CBTS by $9M in 2005/6
load growth	Medium	Medium	Medium
Termination upgrade	5.5	5.5	5.5
Rowville option	11.5	**11.5**	**11.5**
Cranbourne option	**12.1**	**11.5**	11.0
5th 500 kV line	-13.2	-13.2	-13.2

Table 5.12: Net Benefits of projects with Cranbourne 220/66 kV transmission with 6% discount rate

The Cranbourne sites would also involve uncertainties and potential delays resulting from the public approval process which should not be an issue at the already established Rowville site.

There are a number of benefits from establishing the Cranbourne terminal station compared to Rowville option as follows:

- East Rowville and Tyabb loads are presently radially connected from Rowville. By establishing a 220 kV point of connection at Cranbourne the reliability and security of loads supplied from the East Rowville, Tyabb terminal stations and BHP Westernport are increased. The estimated benefit is about $0.34M for the financial year 2003/04 and this increases to $0.70M in the financial year 2011/12. These benefits have been estimated assuming no DSM and local generation.
- The transmission losses will reduce by about 8,100 GWh per year more than the ROTS option with a fuel saving of $0.13M per year.
- The more remote connection from Rowville reduces the fault current level increase at the Rowville 220 kV terminal station and avoids replacement of four 220 kV circuit breakers at Rowville.
- Diversity of 220 kV supply to the Melbourne metropolitan area. Presently around 35% of the total Metropolitan load is supplied from the 220 kV at Rowville. Of this 55% is supplied radially to ERTS/TBTS/BHP Westernport, SVTS/HTS and MTS making these stations completely dependent on Rowville for supply. Establishing a new connection point at Cranbourne would significantly reduce this dependence on Rowville and provide an alternate supply directly to ERTS/TBTS and BHP Westernport and in the case of a catastrophic event at Rowville also provide an opportunity for an alternate source into Rowville. This is difficult to cost and no specific allowance has been made for this in the analysis.

The values of these benefits have been included in the assessment. However with the tolerances of the cost estimates and the possibility of 220/66 kV development, it is not possible to clearly say that the Rowville option is better than the Cranbourne option at this time, due to small difference in net benefits. Details of Cranbourne and Rowville development options are shown in the accompanying Technical Report [5].

5.6 Analysis of Non-network Alternatives

In the Technical Report [5], non-network alternatives were identified for comparison with the network options being considered. As is clear from Table 5.2, the DSM option of 500MW in Victoria has a net benefit which is less than the base case by $0.4M for the termination upgrade and for the 4th line upgrade. DSM does not affect the transmission loss benefits of the upgrade options. Its main impact is on the generation re-scheduling costs and on the reactive support requirement. From the results presented, the DSM option results in lower benefits, because the cost of supplying the reactive support by means of this option is more expensive than providing it with the line upgrade.

In Table 5.2, the impact of an alternative generation development schedule can also be seen. For the market development scenario, which involves the retirement of a 500MW generator in the Latrobe Valley, the net benefit for the Rowville Option is only $2.9M, compared to the base case benefit of $7.5M. This difference is largely due to the lower transmission and generation rescheduling benefits which arise from this option, compared to the base case.

The assessment presented here for the base case shows that whilst DSM and alternative generation developments do deliver some of the four benefits identified in this study, they do not maximise the net benefits.

5.7 Project Timing

Additional sensitivity analysis to those reported in Section 5.2 was conducted to assess the timing of the transmission alternatives.

5.7.1 Rowville option

Base case studies have assumed commissioning of the Rowville option by financial year 2003/04. Table 5.13 shows net benefits of the project for different commissioning times.

Commissioning year	NPV ($M) benefits of the Rowville option		
	6% discount rate	8% discount rate	10% discount rate
2002/03	**12.02**	**7.60**	3.71
2003/04	11.54	7.54	4.09
2004/05	10.84	7.25	4.21
2005/06	10.2	7.00	**4.33**
2006/07	9.36	6.56	4.24

Table 5.13: Net benefits of the Rowville option with commissioning date

Based on this assessment NPV of the Rowville option is highest in financial year 2002/03 for the discount rates 8% and 6%. Timing for the discount rate 10% is financial year 2005/06. The lead time for the project implementation is around 24 months including consultation, tender process, detailed design and construction. The project is timed for 1st December 2003 based on highest benefits for most options by the early commissioning date and marginal reduction in benefits in the financial year 2004/05 compared with the financial year 2005/06 for the 10% discount rate. In addition, this timing takes higher benefits of the project during summer period into consideration.

5.7.2 Cranbourne option

Base case studies have assumed commissioning of the Cranbourne option by financial year 2003/04. Table 5.14 shows net benefits of the project for different commissioning times.

Commissioning year	NPV ($M) benefits of the Cranbourne option		
	6% discount rate	8% discount rate	10% discount rate
2003/04	**7.91**	2.87	-1.48
2004/05	7.75	3.31	-0.46
2005/06	7.59	3.71	0.47
2006/07	7.25	**3.89**	1.15
2007/08	6.42	3.58	1.6
2008/09	5.3	3	**1.74**

Table 5.14: Net benefits of the Cranbourne option with commissioning date

Based on this assessment NPV of the Cranbourne option is highest in financial year 2003/04 for the discount rate 6%. Timing for the discount rates 8% and 10% is financial year 2006/07 and 2008/09. Timing of the Cranbourne option is similar to the Rowville option with a $9M removed from this project and transferred to the 220/66 kV development.

5.8 Summary of results

The Capital costs and estimated range of net benefits for each of the four alternative transmission projects identified to remove the constraint are summarised in Table 6.12.

Transmission Alternative	Median capital cost (estimate $M)	Estimated range of net benefits ($M)	Number of scenarios that maximises the benefits	Number of scenarios with lower costs than benefits
Termination upgrade	2.6	0.5 to 12.4	3	45
Rowville option	23.8	0.0 to 21.9	38	44
Cranbourne option	35.9	-5.6 to 18.3	4	38
5th 500 kV line	71	-32.4 to –6.0	0	0

Table 5.15: Range of net benefit test with alternative transmission projects

As shown above the Rowville option satisfies the ACCC's regulatory test by maximising market benefits for 38 scenarios and by lower costs for 44 scenarios out of 45 credible market scenarios. In effect the total net benefit to all those that produce, distribute and consume electricity in the National Electricity Market is increasing with the project. VENCorp proposes the Rowville option to be commissioned by 31st January 2004 based on higher net benefits to market participants.

6 Conclusion

The analysis shows that the network solution to optimising the Latrobe Valley to Melbourne electricity transmission capacity satisfies the ACCC's regulatory test.

Out of the four network solutions considered "Rowville Option " is the lowest cost alternative with higher benefits for most credible scenarios. Optimum timing for this project is 1st December 2003 based on higher net benefits to market participants. However with the tolerances of the cost estimates and the possibility of 220/66 kV development, it is not possible to clearly say that the Rowville option is better than the Cranbourne option at this time, due to small difference in net benefits.

This project reduces CO2 emissions by about 100,000 CO2 tons per year and a request for approval could be made to the GGAP to register this project for a greenhouse gas grant.

7 Recommendations

Optimise the electricity transmission network from Latrobe Valley to Melbourne by converting the HWTS to ROTS 500 kV line No3, which is currently operating at 220 kV, for 500 kV operation with the associated work at Hazelwood and Rowville end. Capital works of this project is lower than benefits when tested using the ACCC's regulatory test.

It is recommended to tender for both Cranbourne and Rowville options. It is not possible to clearly say that the Rowville option is better than the Cranbourne option at this time, due to small difference in net benefits with considerable tolerances of the cost estimates and the possibility of the 220/66 kV development.

This project reduces CO_2 emissions by about 100,000 CO_2 tons per year and a request for approval to be made to the GGAP to register this project for a greenhouse gas grant.

References

1. NEMMCO[8] 2001 “Statement of Opportunities (SOO), 31 March 2001.
2. NEMMCO Addendum 1 to SOO 2001, June 2001
3. NEMMCO Addendum 2 to SOO 2001, Sept 2001
4. VENCorp[9] “Electricity Annual Planning Review 2001”, April 2001.
5. VENCorp‘s accompanying “Technical Report on optimising the transmission network from Latrobe Valley to Melbourne”
6. IRPC[8] SNI Stage 1 report , October 2001

[8] NEMMCO web site is http://www.nemmco.com.au/

[9] VENCorp web site is http://www.vencorp.com.au/