Appendix G

TEUS Report

TransÉnergie US Limited, *Estimation of Directlink Alternative Projects' Market Benefits*, April 2004

Estimation of Directlink's Alternative Projects' Inter-regional Market Benefits

Prepared for

Allen Consulting Group

By

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1 Executive Summary

Directlink is an HVDC Light transmission interconnector between the Terranora substation in the Gold Coast region of Queensland and the Mullumbimby substation in north-eastern New South Wales. It is capable of delivering up to 180 MW in either direction under normal system conditions.

The Directlink facility provides significant benefits to those who produce, consume or distribute electricity within the National Electricity Market (NEM) because of its ability to provide substantial inter-regional power flows:

1. **Energy benefits** - Reduced energy costs in terms of reduced fuel and variable O&M, and reductions in the frequency and level of voluntary load interruptions.

2. **Deferred market entry generation benefits** – Reduced capital and O&M costs from the deferral of market entry generation.

3. **Deferred reliability entry generation benefits** – Reduced capital and O&M costs from the deferral of reliability entry generation

4. **Residual Reliability benefits** – Reduced cost from lower levels of USE throughout the NEM, after reflecting the impact of the appropriate market entry and reliability entry plant schedules.

Market entry generation is attracted to the market for the purposes of making a profit. Reliability entry generation can be procured by NEMMCO in its role as the reserve trader under the Code, which is to ensure that expected USE in the NEM is held below the Reliability Panel's reliability standard, currently 0.002% of energy consumed.

The Directlink facility also provides significant benefits because of its ability to provide substantial network support to north-eastern New South Wales and the Gold Coast and, thus, its ability to defer transmission augmentations that would otherwise be necessary. Estimates of these benefits have been calculated outside of this report.

The owners of Directlink are applying to the Australian Competition and Consumer Commission (ACCC) for Directlink's network service to be classified as a prescribed service and to receive a regulated revenue. In making its decision, the ACCC will have regard to the market benefits that a range of alternative projects comparable to Directlink could provide to the NEM.

Burns and Roe Worley (BRW) has identified seven comparable alternative projects for applying the Regulatory Test to Directlink. However, one alternative does not provide inter-regional power flows and BRW considers that another two alternative projects are not a reasonable alternative to Directlink for the purposes of the Regulatory Test. So TransÉnergie US Limited (TEUS) has not calculated the inter-regional market benefits of these three projects.

This report describes TEUS's estimation of the four types of benefits that arise from Directlink's alternative projects ability to provide substantial inter-regional power flows[1], including the input data sources, assumptions and methodology used to calculate monthly cash flows representing these market benefits over a 40 year horizon beginning on January 1, 2005 and ending December 31, 2044 under a range of market development scenarios.

The input data, assumptions and methodology are consistent with those presented in the 2003 Statement of Opportunities published by the National Electricity Market Management Company (NEMMCO) in July 2003, except where noted otherwise.

Energy benefits for each alternative project have been estimated by using the PROSYM chronological production cost simulation model and taking the difference between:

- the energy costs calculated in a scenario without the project in place (the "Without" scenario); and
- the energy costs calculated in a scenario with the project in place (the "With" scenario).

The PROSYM model has also been used to develop schedules of market entry generation by region, that is, the generation that is attracted to the market for the purposes of making a profit. TEUS has calculated changes in regional prices over time and, assuming that new plant will enter the market when regional prices allow all such entry to be profitable on a sustained basis, prepared a market entry schedule for the Without and With scenarios that describes what generation would enter the market, where, when and at what capital and O&M cost. The deferred market entry generation benefit is calculated as the capital and O&M cost saving indicated by the market entry schedules.

Reliability benefits are estimated by measuring the difference in total expected unserved energy throughout the NEM between the Without and With scenarios for each alternative project, using the General Electric's Multi-Area Reliability Simulation model (MARS). MARS is a chronological Monte Carlo simulation tool specifically designed to measure reliability in multi-area systems such as the NEM.

The MARS model is also used to identify when NEMMCO, as the reserve trader, would add reliability entry generation to ensure each region within the NEM remains in compliance with the reliability standard set by the Reliability Panel under the Code. Currently, this standard mandates that expected USE be less than or equal to 0.002% of electricity consumption. A reliability entry schedule is developed that, in combination with the market entry schedule, ensures reliability requirements are met.

The results of TEUS's study of Directlink's alternative projects' market benefits are summarized in Table 1.1 below. This table provides the cumulative present worth at January 1, 2005 of inter-regional market benefits for all evaluated scenarios. These are the benefits that each alternative project would provide from January 1, 2005 to December 31, 2044.

[1] The estimation of transmission augmentation deferral benefits is discussed in BRW's report, "Application of Regulatory Test including Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC".

Summary of Inter-Regional Market Benefits

9%		$10,000 Value of USE: Results (Ave of Termination in Yrs 2015-2019)			$29,600 Value of USE: Results (Ave of Termination in Yrs 2015-2019)		
Alternative	Bidding	High	Med	Low	High	Med	Low
0, 1 and 2	LRMC	156,920	112,327	68,886	146,587	111,328	66,189
0, 1 and 2	SRMC		33,613			63,964	
3	LRMC	125,940	88,177	89,431	76,416	71,969	86,859
3	SRMC		11,722			21,731	

7%		$10,000 Value of USE: Results (Ave of Termination in Yrs 2015-2019)			$29,600 Value of USE: Results (Ave of Termination in Yrs 2015-2019)		
Alternative	Bidding	High	Med	Low	High	Med	Low
0, 1 and 2	LRMC	183,444	103,322	46,330	166,352	96,984	38,365
0, 1 and 2	SRMC		15,891			54,556	
3	LRMC	119,128	73,130	74,373	49,616	45,636	66,952
3	SRMC		(13,469)			(4,051)	

11%		$10,000 Value of USE: Results (Ave of Termination in Yrs 2015-2019)			$29,600 Value of USE: Results (Ave of Termination in Yrs 2015-2019)		
Alternative	Bidding	High	Med	Low	High	Med	Low
0, 1 and 2	LRMC	137,408	114,240	78,663	131,715	116,838	79,542
0, 1 and 2	SRMC		44,518			69,467	
3	LRMC	126,787	94,431	93,792	90,899	85,803	94,517
3	SRMC		27,751			38,166	

Table 1.1

2 Background and Context

2.1 Purpose of the Report

The owners of Directlink are applying to the ACCC for Directlink's network service to be classified as a prescribed service and to receive a regulated revenue. In making its decision, the ACCC will have regard to net market benefits that a range of alternative projects comparable to Directlink could provide to all those who produce, distribute and consume electricity in the NEM.

The Directlink Joint Venture, through the Allen Consulting Group, has engaged TEUS to calculate the market benefits of Directlink's alternative projects that arise from the projects' abilities to transfer power between regions in the NEM.

The purpose of this report is:

- to articulate TEUS's estimate of these market benefits, and
- to explain the manner in which these market benefits have been calculated.

The market benefits, calculated by TEUS and documented in this report, will be used as an input for the application of the ACCC's *Regulatory Test for New Interconnectors and Network Augmentations* (Regulatory Test) to the Directlink transmission asset.

The costs of the alternative projects, the resulting net market benefits, and the extent to which Directlink satisfies the ACCC's Regulatory Test are not addressed in this report. These topics are the subject of other reports incorporated into Directlink Joint Venture's application to the ACCC.

2.2 History

Directlink is a 63 kilometer underground transmission facility using HVDC Light technology that interconnects Queensland and New South Wales. It was placed into commercial operation in July 2000. HVDC Light technology incorporates sophisticated power control electronics and advanced cable technologies in a single transmission system. This technology provides several significant technical capabilities:

- Direction and magnitude of power flows can be fully controlled.
- Voltage source converter technology requires less filtering than conventional HVDC technology, which leads to higher reliability and a more compact design.
- AC system voltage or reactive power exchange with the local AC network can be readily controlled.

Active power transfer over HVDC facilities is directly controlled by electronic valves at converter stations at each end of the Directlink facility. The valves convert AC electrical energy into DC electrical energy (and vice versa) and control the power flow between the converter stations. The firing control for each valve allows for the rapid control of power transfers and fast response to changing AC system conditions.

2.3 Description of Directlink's Alternative Projects

BRW has identified seven alternative projects comparable to Directlink:

Alternative 0 – The Directlink project with the addition of post-contingent network support capability and reactive support in the Gold Coast.

Alternative 1 - A modern HVDC Light link with 180 MW capacity with protection and control systems to National Electricity Code standards including dynamic active and reactive power support, and emergency response.

Alternative 2 - A conventional HVDC link with 180 MW capacity along with synchronous condensers at both ends, protection and control systems to Code standards including dynamic active and reactive power support, and emergency response.

Alternative 3 - A HV link with 180 MW capacity along with a phase shifting transformer, and capacitors at each end, protection and control systems to Code standards including emergency response.

Alternative 4 - A HV link with 180 MW capacity along with an auto-transformer and capacitors at each end, protection and control systems to Code standards.

Alternative 5 - HV network augmentations in New South Wales and the Gold Coast designed to solely address the emerging network limitations in those areas due to load growth.

Alternative 6 - Approximately 180 MW of embedded generation in the Gold Coast and far north east of New South Wales, and a demand management program.

Given that Alternative 5 does not provide inter-regional power flows and that BRW considers that Alternatives 4 and 6 are not reasonable alternatives to Directlink for the purposes of the Regulatory Test, TEUS has not calculated the inter-regional market benefits of these three projects.

We understand that Alternatives 0, 1 and 2 differ in several respects and that the extent to which each can provide local network support varies materially. However, the relevant technical features of Alternatives 0, 1 and 2 are similar enough for them to be considered the same for the purposes of TEUS's calculations of inter-regional benefits. TEUS has tested this by undertaking separate calculations for Alternative 2. From this point, our analysis will focus on the market benefits on two alternative project cases:

- Alternatives 0, 1 or 2 - the DC alternative projects; and
- Alternative 3 - the AC alternative project.

2.4 The Regulatory Test

Under the Regulatory Test:

> "market benefit" means the total net benefits of the proposed augmentation to all those who produce, distribute and consume electricity in the NEM. 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.

The market benefit calculation must be performed for a range of scenarios that examine reasonably probable alternative assumptions for the key factors that determine market benefits. These factors include market development (i.e. economic growth) scenarios, commercial discount rates, and generator bidding strategies, and the value of unserved energy.

2.5 Types of market benefits

Four principal types of market benefits that arise from a project's ability to transfer power between regions in the NEM have been identified and estimated in this report:

1. **Energy benefits** - Reduced energy costs in terms of reduced fuel and variable O&M, and reductions in the frequency and level of voluntary load interruptions.

2. **Deferred market entry generation benefits** – Reduced capital and O&M costs from the deferral of market entry generation.

3. **Deferred reliability entry generation benefits** – Reduced capital and O&M costs from the deferral of reliability entry generation

4. **Residual reliability benefits** – Reduced cost from lower levels of USE throughout the NEM, after reflecting the impact of the appropriate market entry and reliability entry plant schedules.

2.5.1 Energy Benefits

The existence of an interconnector between Queensland and NSW increases the opportunities to displace more expensive generation in one region with less expensive generation in another region. When energy flows over the interconnector in response to such opportunities, total system fuel and O&M costs are reduced, providing important energy-cost-related market benefits to the NEM.

2.5.2 Deferred Market Entry Generation Benefits

Market entry generation is attracted to the market for the purposes of making a profit.

The addition of an interconnector between Northern NSW with the Gold Coast will cause prices to change in each NEM region, but particularly in Queensland and New South Wales. The resulting prices are generally lower, both on an all-hours annual basis and an on-peak basis. Lower prices are less profitable for new market entry generation. This price reduction causes entry of new market generation to be deferred until there is sufficient load growth to offset project's impact on prices. The deferral of capital spending and fixed O&M for new market entry plant represents a market benefit.

2.5.3 Deferred Reliability Entry Generation Benefits

Each of Directlink's alternative projects allows generation capacity in the NEM to be shared more efficiently, thus reducing the underutilization of that capacity. Limits to the transmission system that prevent the natural diversity in peak demands between regions from being fully captured are contributors to underutilization. The unpredictability of forced outages is another.

Higher reserve levels are necessary to provide adequate reliability when a region is unable to share available reserves in adjacent regions. Increased transfer capability between regions, such as one of Directlink's alternative projects provides, makes this reserve sharing possible and, thus, increases system reliability for a given investment in generating plant.

USE results when either:

- the installed generation capacity is unable to provide enough energy to serve the entire NEM load at some point in time; and/or
- transmission constraints prevent energy available at a generating unit from being delivered to the point of consumption.

Even when sufficient market entry generation is installed to meet the Reliability Panel's unserved energy standard, USE can still occur due to generation or transmission forced outages or non-interruptible demands that unexpectedly exceed the forecast demand.

Reliability entry generation can be procured by NEMMCO in its role as the reserve trader under the Code, which role is to ensure that expected USE in the NEM is held below the Reliability Panel's reliability standard, currently 0.002% of energy consumed. Should market forces not stimulate the adequate entry of new generation, it is presumed that NEMMCO will contract for the necessary generation reserve.

As each of Directlink's alternative projects allows generation capacity in the NEM to be shared more efficiently, it can reduce the extent to which NEMMCO may have to procure reliability plant. The reduction of capital spending and fixed O&M for new reliability entry plant represents a market benefit.

2.5.4 Residual Reliability Benefits

Market entry generation and reliability entry generation will reduce, but generally not eliminate unserved energy. This residual USE provides a way to quantify the level of "unreliability" remaining in the NEM after all generation and demand-side resources, and reserve-sharing capabilities have been fully utilized. Reductions in residual unserved energy represent a benefit to the market. Although a reduction in USE could be viewed as an energy benefit, the value of reductions in residual USE has not been included in the calculation of energy benefits, but instead is modeled in much greater detail using the MARS model as part of the calculation of reliability benefits.

2.5.5 Other Benefits

Most of Directlink's alternative projects can also defer the cost of transmission augmentations necessary to provide network support to the Gold Coast and northeastern New South Wales. These benefits are not addressed in this report but are estimated by BRW in "Application of Regulatory Test including Selection and Assessment of Alternative Projects to support Conversion Application to ACCC", included as Appendix D of the Directlink Application for Conversion.

Alternatives 0, 1 and 2, which incorporate HVDC technology[2], with some additional augmentation, can also provide additional market benefits, the value of which is difficult to quantify, and which have not been considered in this analysis (thus understating the market benefits provided). These additional market benefits include:

- The ability to provide frequency control ancillary services, by operating in frequency control mode; and
- The ability to automatically control AC voltages while simultaneously providing real power transfer capability.

2.6 Modeling Software Used to Estimate Inter-regional Market Benefits

Two different commercially available electric system simulation models are used to calculate the projected energy, reliability, and deferred market entry benefits that Directlink provides.

2.6.1 PROSYM

The PROSYM Chronological Production Modeling System is a comprehensive modeling package specifically designed for the estimation of energy costs and electricity prices in large, complex markets. The software has been licensed by TEUS from Henwood Energy Systems, a consulting firm with offices in both the United States and Australia and with experience in modeling the Australian NEM.

PROSYM is a chronological production cost model that simulates the operation of a multi-area generation and transmission system, reflecting the operation, maintenance and forced outage characteristics of generators, transmission interconnections between the areas, and the projected hourly loads of the areas. It provides the capability to model the cost and operating characteristics of individual generators within several interconnected regions, and is well suited for use within the five-region structure of the NEM. Seasonal limitations on the transfer of power between regions are specified. On an hour-by-hour basis, PROSYM dispatches the generators in each region to serve the region's load in a manner that minimizes the total cost of electricity production—importing power from adjacent regions when

[2] A complete description of the Alternative Projects 0 through 6 is provided in BRW's report included in Appendix D of the Directlink Application for Conversion.

that power is less expensive than local generation or exporting power when local generation can displace more expensive generation in neighboring regions. The model simulates the impact of maintenance requirements and forced outages, and the specific operating limitations of each generating facility. The dispatch of generation and interregional transfers are simultaneously optimized across the five regions.

2.6.2 MARS

The General Electric Multi-Area Reliability Simulation (MARS) model is a commercially available reliability planning tool licensed by TEUS from General Electric's Power Systems Engineering Consulting group in Schenectedy, New York. MARS provides sophisticated capabilities to model uncertain load forecasts, generator outage and availability characteristics, maintenance schedules, capacity contracts and reserve sharing agreements. It has been used by TEUS to model the reliability impacts of HVDC facilities in a representation of the northeastern United States and eastern Canada incorporating 45 regions, more than 2500 generators, and 78 transmission interfaces. MARS provides more than enough detail and flexibility to accurately model the operation of the NEM—a single integrated system represented as 12 separate regions, all operating under a common set of rules.

MARS is a stochastic simulation model that uses a Monte Carlo approach to estimating reliability parameters. Each year is simulated chronologically for a number of samples, using randomly determined generator outages. Reliability indicators, including the total system unserved energy, are calculated for each sample. By averaging the unserved energy from a large number of randomly generated samples, the expected unserved energy, also known as the loss of energy expectation (LOEE) is determined. This is the primary reliability indicator used in the Directlink analysis. It directly and transparently captures reliability impacts throughout the entire NEM valuing unserved energy in any region equally, and implicitly incorporates both the size and duration of capacity shortfalls. Furthermore, it is a reliability measure explicitly recognized and quantified in the NEM as the value of unserved energy.

The MARS model implements a stochastic reliability simulation methodology that is quite similar to approaches used previously in the NEM. The NECA Reliability Panel used a similar modeling approach in 1999 to develop the reserve trigger levels used as part of the reserve trader mechanism. More recently, the same approach has been used by TransGrid to develop optimal reserve margins for each region in the NEM.

2.7 Report Structure

The report presents a detailed description of the inputs, assumptions and methodology used to calculate the market benefits of Directlink's alternative projects under a range of scenarios, including economic growth rates, generator bidding strategies, economic discount rates, the value of unserved energy and the capital and operating costs of generators in the NEM. The information is presented in several sections:

- Energy and deferred market entry generation benefits

- Deferred reliability entry generation and residual reliability and benefits
- Scenarios and results.

Three appendices provide detailed results, a summary of generator characteristics, and a summary of the load forecasts used in the three scenarios analyzed. Following the appendices, a list of references is provided.

3 Calculation of Energy and Deferred Market Entry Generation Benefits

3.1 Inputs, Assumptions, and Information Sources

The PROSYM model requires detailed inputs regarding loads, generator characteristics, fuel costs, bidding behavior, and simplified transmission network topology and constraints.

TEUS has quantified energy and deferred market entry generation benefits by using published data and mainly that documented in:

- the 2003 *Annual Interconnector Review* (2003 AIR) published by the Inter-Regional Planning Committee (IRPC) in April 2003; and
- *SRMC and LRMC of Generators in the NEM* (ACIL Tasman Report), published by the IRPC and NEMMCO in April 2003; and.
- the *2003 Statement of Opportunities* (2003 SOO), published by NEMMCO in July 2003,

The PROSYM model can also utilize detailed generator performance characteristics such as heat rate curves, maintenance schedules, startup costs, and variable O&M costs when such information is available. It is also capable of producing results using only more aggregated assumptions, such as maintenance days per year by generator type and "all-in" estimates of each generator's fuel and variable operating cost expressed in $/MWh. In general, as most generators consider detailed performance characteristics to be commercially sensitive, only more aggregated information is available.

3.1.1 Evaluation Time Horizon

Directlink was placed into service in July 2000, and is currently operating as a market network service provider within the NEM. Directlink's design life is 40 years, indicating a retirement date of July 2040. TEUS's analysis considers the period from January 1, 2005 through December 31, 2044, a 40 year period. In all likelihood, Directlink's actual operational life will be greater than 40 years, so the assumption of Directlink retirement in 2044 is reasonable.

The PROSYM modeling covers fifteen calendar years 2005–2019 (modeled monthly). By sometime after 2014, the modeling of the NEM is anticipated to have reached or be oscillating around a long run equilibrium condition. Results for all following years, excluding any further capital costs or savings for market entry or reliability entry plant, are assumed to replicate the termination year results on a monthly basis. Because of the large size and high cost of market entry coal plants and their impact on energy costs, the termination year results can be sensitive to the timing of coal plant entry. The estimated inter-regional market benefits, therefore, reflect an average of estimates based on 5 different termination years, 2015 through 2019. TEUS believes this provides a robust and unbiased estimate of long run equilibrium outcomes.

3.1.2 Inflation and Discount Rates

All cost and financial assumptions are derived from the ACIL Tasman Report on short run and long run marginal costs, and are indicated by the report to be in "2001/02 terms". Using the midpoint of this period, TEUS interprets this to mean the costs are stated as in January 1, 2002 dollars. We have restated the costs in January 1, 2005 dollars using the Australian "All Cities" consumer price index for December 31, 2001 and December 31, 2003, plus 12 months at an annual inflation rate of 2.22%. Combined, this results in a 7.81% inflation adjustment applied to all generator cost estimates.

In calculating the net present value (NPV) numbers shown in the Executive Summary, an annual discount rate of 9% was used with sensitive testing at 7% and 11%.

3.1.3 Network Topology and Constraints

The topology of a multi-area transmission system, including the limits and constraints on flows between areas is an important determinant of the simulated operation of the system. The existing five-region structure of the NEM, as shown in Figure 2.1, is represented within the PROSYM model. The PROSYM representation includes two additional "artificial" regions (i.e. a region not defined in the NEM's current configuration) to facilitate the modeling of the Directlink and Murraylink HVDC transmission links.

PROSYM, by default, is only capable of representing a single transmission link between any two regions. The artificial regions have been introduced as a modeling device to enable power transfers over the QNI and Directlink interconnectors, and the Heywood and Murraylink interconnectors to be separately observed. The artificial regions are modeled with no load and no generation, and two links, connecting the each artificial region to QLD and NSW for Directlink, and SA and VIC for Murraylink. The pairs of link from QLD and NSW to the Directlink Artificial Region together represent the Directlink facility. Similarly, the pair of links connecting SA and VIC to the Murraylink artificial region together represent Murraylink.

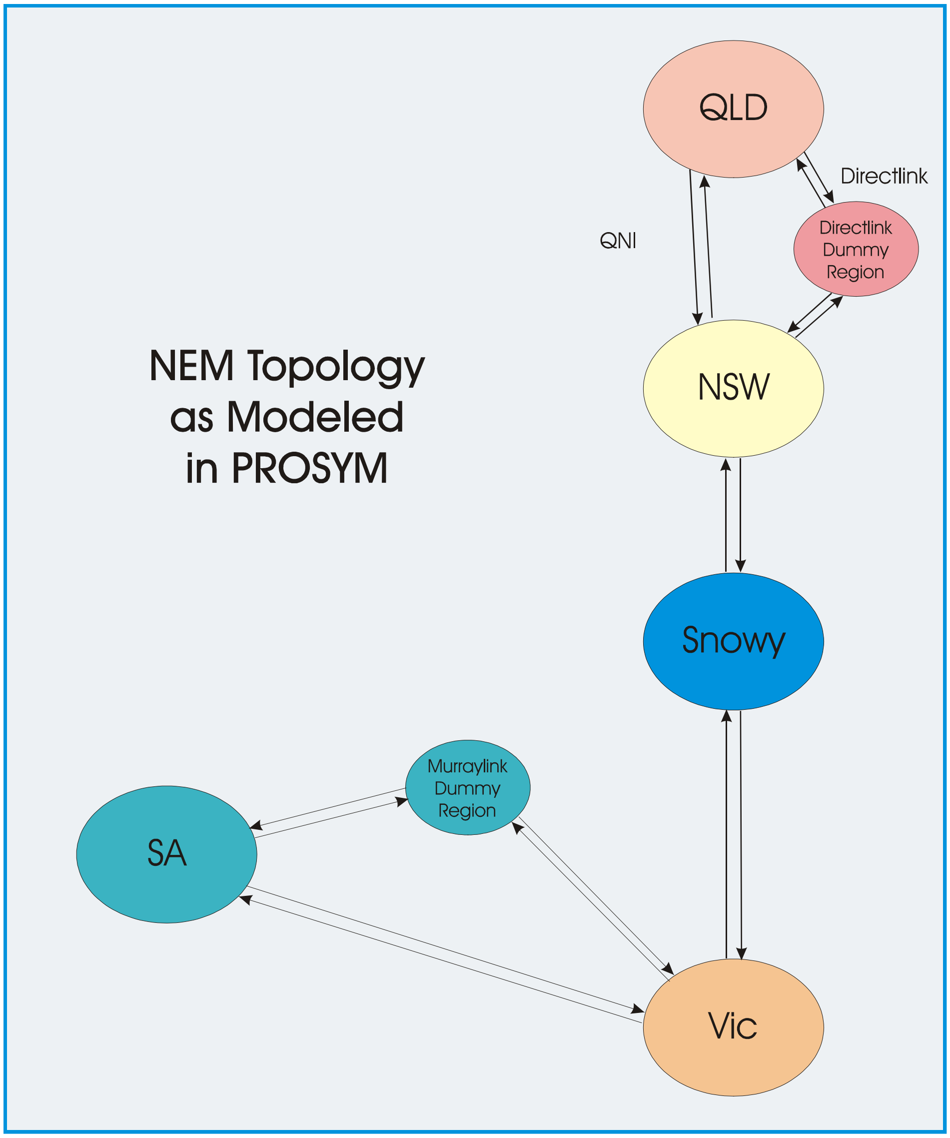

Figure 3.1

The NEM operates using detailed “constraint equations” that define limits on interconnector flows in relation to load and generation patterns that will ensure the transmission system will operate reliably. The PROSYM model provides flexibility to model transmission limits that change cyclically over time (i.e. seasonally, by time of day, by day of week), but it does not provide a means of implementing dynamic constraints that change as a function of load or generation. Consequently, the detailed constraint equations have been represented within the PROSYM model with seasonal interface limits using information provided in the 2003 SOO.

The PROSYM modeling is an hourly simulation of the 15 year period 2005–2019 on a pre-contingent, or “all lines in” basis. TEUS has assumed the AC network will support power transfers over the various regional interfaces at the power transfer levels identified in the 2003 SOO. These limits are shown in Table 3.1.[3]

Interface Limits Used in Prosym		
Interface	Positive Direction	Negative Direction
Queensland to New South Wales (QNI)	950	700
Queensland to New South Wales (DL)	125	180
New South Wales to SNOWY	1150 1150	2800 (summer) 3200 (winter)
Victoria to SNOWY	1100	1900
Victoria to South Australia (Heywood)	460	300
Victoria to South Australia (Murraylink)	220	120

Table 3.1

Murraylink flows can be constrained when the NEM is operating under stressed, peak-load conditions. To reflect these constraints, flows from Victoria to South Australia through the Murraylink artificial region are limited to 110 MW during hours representing summer peak conditions. Similarly, flows from South Australia to Victoria are constrained to no more than 150 MW in winter (March–November), and to the following time-of-day limits during the summer (December–February):

10 am–8 pm	95 MW limit
8 pm–10 am	130 MW limit

Transmission maintenance is assumed to be planned for periods when it would not have meaningful impacts on NEM reliability or NEM energy costs. PROSYM does not provide a direct means of simulating unplanned transmission outages.

3.1.4 Load Traces

Hourly load traces for the five NEM regions for the PROSYM analysis were developed by TEUS using 2003 actual half-hourly load data published by NEMMCO to define the regional load shapes, and forecast annual energy and peak demand published in the 2003 SOO to define the annual characteristics of the load traces. 2003 historical data was selected primarily because it is current and likely to reflect changing energy usage trends reasonably well, and because it was available on a consistent basis for all NEM regions. As the benefits provided by an interconnector

[3] The PROSYM model provides only very limited capabilities to model dynamic limits, i.e. those that change with system conditions. TEUS adopted limits for the PROSYM hourly energy simulations thought to represent typical conditions throughout the year, recognizing that such an approximation may result in inaccuracies during non-typical conditions.

are likely to depend heavily on the amount of load diversity between regions, the use of different historical years for different regions would inject a false level of weather-related diversity. The weather patterns that drive peak loads are interrelated and correlated. The use of a single year's data ensures regional weather-related diversity is handled consistently and appropriately.

The annual load traces were developed in several steps:

1. The 2003 half-hourly loads were converted to hourly loads by letting each hourly load equal the maximum of the two respective half-hourly loads.

2. Loads were then shifted up to three days forward or backward to ensure the correct day-of-the-week alignment for the forecast year

3. All hourly loads were scaled up (or down) to allow the annual peak load to match the forecast peak for the year.

4. All remaining loads were scaled proportionately based on their relationship to the annual peak demand such that the sum of the hourly loads matched the forecast annual energy.

New South Wales is forecast to change from winter peaking to summer peaking in 2012, preventing the method outlined above from being applied, as it would simply perpetuate the winter peak reflected in the 2003 historical data. To capture the changing seasonality of loads in NSW, a similar process was applied, but on a monthly basis. A forecast of monthly peak demands and energies was created, assuming that 2003 monthly peaks would grow at their forecast seasonal growth rates. 2003 monthly energies were forecast by applying the same seasonal peak demand growth rates, and then normalizing the resulting values to match to annual energy forecast. Once the monthly peak and energy forecasts were developed, the four-step process described above was applied using 2003 historical NSW loads to create hourly load traces that preserve the change from winter peaking to summer peaking in 2012.

The same process was repeated for the medium, high, and low economic growth 50% probability of exceedance (POE) load forecasts for Queensland, New South Wales, South Australia, and Victoria. Load in the Snowy region was assumed to be 1 MW, and Tasmania was not directly modeled (see discussion of Basslink in Section 3.1.14). A summary of the annual peak demands and energies for each economic growth scenario is provided in Appendix 3 of this report.

3.1.5 Market Entry Generation Characteristics

As described in the ACIL Tasman Report on marginal costs, three basic types of market entry new generation were considered – open cycle gas turbine (OCGT) peaking units, combined cycle gas turbines (CCGT), and coal fired generation. New coal units in New South Wales and Queensland were assumed to burn black coal, and new Victorian coal generators were assumed to burn brown coal.

Potential Merchant Entry

	Open Cycle Gas Turbine	Combined Cycle Gas Turbine	Black Coal	Brown Coal
Queensland	X	X	X	
New South Wales	X	X	X	
Victoria	X	X		X
South Australia	X	X		

Table 3.2

The different types of generation are assumed to have the cost structures published in the ACIL Tasman Report:

New Generation Costs

Technology	Capital Cost $/KW	Fixed O&M $/KW-Yr	Annualized Cost Jan 2001 $/KW-Yr	Annualized Cost adj to Jan 2005 $/KW-Yr	SRMC Jan 2001 $/MWH	SRMC Jan 2005 $/MWH	Size MW
Combined Cycle Gas Turbine - QLD	1,000	36.36	186.40	200.90	21.30	22.96	385
Combined Cycle Gas Turbine - NSW	1,000	36.36	186.40	200.90	23.51	25.34	385
Combined Cycle Gas Turbine - VIC	1,000	36.36	186.40	200.90	23.14	24.94	385
Combined Cycle Gas Turbine - SA	1,000	36.36	186.40	200.90	26.08	28.11	385
Open Cycle Gas Turbine	500	10.00	85.00	91.61	62.06	66.89	100
Black Coal - QLD	1,400	44.44	254.44	274.24	6.78	7.31	450
Black Coal - NSW	1,400	42.00	252.00	271.61	9.03	9.73	500
Brown Coal - VIC	1,800	50.00	320.00	344.90	4.87	5.25	500

Table 3.3

The amount, type, and location of new generation was not assumed, but was determined through the modeling process, as described in Section 3.2.

3.1.6 Existing and Committed Generation Characteristics

The characteristics of existing and committed generators required by the PROSYM and MARS models have been taken from the ACIL Tasman Report. The characteristics include:

- Region
- Seasonal maximum capacity ratings (winter ratings March–-November, summer ratings December—-February)
- In-service and retirement dates
- Marginal loss factor
- Forced outage rate

- Annual maintenance requirement
- Mean time to repair
- Short run marginal cost.

TEUS adopted the ACIL Tasman Report's SRMC estimates as each generator's bid price, which is used by PROSYM to select which units will operate to serve the load, and as the best estimate of each generator's actual fuel and operating cost. For several of the larger baseload generators, an initial block of the generator's maximum capacity is bid at $0/MWh to simulate minimum loading requirements for these facilities. The sizes of the initial block in the different NEM regions are:

Victoria is	65%
South Australia	55%
New South Wales	40%
Queensland	40%

The specific values used for each generator are summarized in Appendix 2.

3.1.7 Bidding Behavior

Generators are assumed to bid either their LRMC or their SRMC, depending on the scenario assumptions. The development of these cost estimates is described in the following sections.

3.1.7.1 LRMC Bidding

The ACIL Tasman Report provided specific estimates of LRMC only for generic new generating plant. For existing generators, TEUS developed LRMC proxy prices by adding $20/MWh to each generator's SRMC. This produced output market prices sufficiently high to attract coal entry within the first five years of the analysis. It also produced 2005 market prices approximately 50% higher than actual 2003 market prices, and generally in the range of the total cost per MWh for new generation, as reported by ACIL Tasman. While the "true" long run marginal costs of existing generators (if they were even possible to determine) may differ from the TEUS-developed LRMC proxy prices, the proxy prices produce overall results consistent with what one would expect when market participants bid their long run costs. TEUS believes they form a reasonable basis for scenario analysis.

3.1.7.2 SRMC Bidding

Short run marginal costs for each existing generator were taken from information published in the ACIL Tasman Report. They are assumed to include fuel and any variable operating cost for each generator.

3.1.7.3 Interconnector Bidding

TEUS has modeled each of Directlink's alternative projects as a regulated interconnector. Hence, its transport capacity is not bid into the market. Instead, it is assumed to follow dispatch instructions from NEMMCO with no "transport charge". The NEMMCO dispatch then minimizes the total energy cost of dispatched generation and interruptible load, recognizing the generating unit capacities, hourly demands, interconnector losses, and transmission constraints.

3.1.8 Losses

The PROSYM model allows quadratic loss equations (where losses are a function of flows) to be specified for each interconnector. These equations were developed from the interregional dynamic loss equations described in the 2003 SOO.

Electrical losses over Alternatives 1 and 2, HVDC projects similar to Directlink, were based on Directlink's measured electrical losses as reported to NEMMCO, and then fitted to the quadratic equation format required in PROSYM. Losses over the other alternative projects were based on standard engineering calculations for a line with the given length, voltage, and capacity.

Alternative 0, 1, and 2 Loss Equation:

$$-0.0013*\text{Flow} + 2.7372*10\text{-}4*(\text{Flow})^2$$

Alternative 3 Loss Equation:

$$-0.0654 + 0.0027*\text{Flow} + 0.0003*(\text{Flow})^2$$

3.1.9 Hydro Information

The 2003 SOO provided basic information on hydro generation capacity and monthly production profiles for Snowy Hydro. Information on Southern Hydro monthly production was obtained from the NEMMCO web site.

3.1.10 Heywood Derating

The Heywood interconnector is vulnerable to outages caused by electrical storm activity. To avoid unacceptable consequences of a lightning strike, the interconnector is often derated. A discussion paper by the South Australian Independent Industry Regulator provided historical data regarding the causes and frequency of derates of the Heywood interconnector, which was used to develop outage parameters for use in the MARS model. The paper titled Transmission Line Performance in South Australia & the SA Transmission Code was published in December 2001. The PROSYM model does not provide a direct means of modeling transmission outages, and the modeling of energy benefits does not reflect Heywood outages.

3.1.11 Demand-Side Impacts

The PROSYM modeling incorporates two forms of demand-side response during periods of tight supply—voluntary load reduction and involuntary load reduction, which is the direct cause of USE.

NEMMCO has published estimates in the 2003 SOO of the amount of voluntary load reduction available in the NEM dispatch. Interruptible load amounts available at indicated pricing are shown in Table 3.4. PROSYM essentially treats the interruptible load like additional generation available for dispatch when market prices would otherwise exceed the interruptible load price.

Interruptible Load MW				
Price $/MWH	SA	VIC	NSW	QLD
500	9	27	0	0
1,000	12	36	0	0
3,000	18	54	0	0
5,000	21	62	31	25

Table 3.4

3.1.12 Maintenance

Maintenance schedules are developed by PROSYM for each year using a "distributed maintenance levelized loss of load probability" algorithm. TEUS developed annual maintenance rates for each unit from information in the 2003 SOO.

3.1.13 Value of Unserved Energy

Unserved energy (USE) results when the PROSYM model is unable to dispatch sufficient generation to meet all demands. For purposes of developing the electricity market prices on which new entrant profitability is determined, the unserved energy is priced at $10,000 per MWh, the assumed wholesale market price cap. The reductions in USE calculated in the PROSYM simulations are not used to calculate energy benefits or the reliability benefits. TEUS has more accurately estimated reductions in USE using MARS and used the MARS results to calculate the residual reliability benefits, as described in section 4.2.

3.1.14 Basslink

The Basslink interconnection with Tasmania is modeled is PROSYM as a pumped storage facility, with a "generating capacity" (i.e. transfer capacity from Tasmania to Victoria) of 600 MW, and a "pumping capacity" (i.e. transfer capacity from Victoria to Tasmania) of 300 MW. Losses of 6.3% are assumed for transfers in either direction, based on estimates of maximum sending capacity and maximum received capacity reported in the 2003 SOO.

3.2 Methodology

3.2.1 Overall Approach

TEUS's methodology for the calculation of energy and deferred market entry generation benefits follows the approach originally adopted by the IRPC in its document IRPC Stage 1 Report: Proposed SNI Interconnector, Version V014, published on October 26, 2001, and later refined by the ACCC in its 2003 decision on Murraylink Transmission Company's application for Murraylink to be converted to regulated status.

Energy benefits for each alternative project have been estimated by using the PROSYM chronological production cost simulation model and taking the difference between:

- the energy costs calculated in a scenario without the project in place (the "Without" scenario); and
- the energy costs calculated in a scenario with the project in place (the "With" scenario).

This simulation process also measured the benefits attributable to the alternative projects from reducing the amount of voluntary interruptible load actually interrupted.

The PROSYM model has also been used to develop schedules of market entry generation by region, that is, the generation that is attracted to the market for the purposes of making a profit. TEUS has calculated changes in regional prices over time and, assuming that new plant will enter the market when regional prices allow all such entry to be profitable on a sustained basis, prepared a market entry schedule for the Without and With scenarios that describes what generation would enter the market, where, when and at what capital and O&M cost. The deferred market entry generation benefit is calculated as the capital and O&M cost saving indicated by the market entry schedules.

3.2.2 Competitive Market Entry Modelling Procedure

The schedule of market entry plant is developed by simulating the competitive market investment decisions made by profit-seeking firms, based on simulated regional hourly energy prices in the NEM. These hourly energy prices are developed using the PROSYM model through an iterative year-by-year market simulation process.

In each year, if hourly prices over the year are high enough such that a market entry generator's energy revenues exceed its long-run marginal cost (energy cost plus the annual levelized fixed cost), a new market entry generator is added. The PROSYM simulation is then repeated and the market entry generator profitability test is reapplied, until the next market entry generator is no longer economically viable. More specifically, the "profitability" of each potential new generator is examined, and if the inclusion of additional plant lowers hourly market prices to a level that will not cover the generator's long-run marginal cost, it will not be added to the generation-mix. For convenience, all new generation is added at the beginning of the calendar year.

Each year is simulated separately, and builds upon all prior year's market entry. Once a plant has entered, it is assumed to remain in the market and operate through the modeling horizon (no retirements). When several generator types/locations are profitable, the generator that is "most" profitable is added first. It is assumed that each generator acts independently and in its own self interest, and does not take into account its impact either on other generator types entering in the same year or those entered in the prior years. If after entering, a plant remains profitable but causes prior entrants added in earlier iterations to become unprofitable, the new plant is assumed to displace the prior entrant. The prior entrant is removed, the year is resimulated, and the profitability test is reapplied.

Market entry plants that are within $2/KW-Yr of profitability are considered to break even if other market entry of the same type in the same location has positive margins. This is done to recognize that PROSYM's maintenance scheduling algorithm may result in a small disadvantage to some units because their maintenance happened to be scheduled during periods with slightly higher market prices. With a better optimized maintenance plan, these units would break even.

3.2.3 Modelling Steps

The PROSYM modeling of energy and deferred market entry generation benefits for each alternative project follows several steps:

- Development of a long run market equilibrium simulation with the alternative project in service based upon market entry of new generation in response to regional prices[4] resulting from short run/long run marginal cost bidding behavior for each generator.

- Development of a similar long run equilibrium without the alternative in service.

- Quantification of the market benefits of deferring market entry generation resulting from the presence of the alternative project.

- Quantification of the difference in variable generation costs (fuel plus variable O&M) on a monthly basis between the With and Without scenarios.

- Quantification of the difference in voluntary load reductions (also referred to as interruptible load or dispatchable demand) on a monthly basis between the With and Without scenarios.

3.2.4 Required Simulations

As described in Section 3.2.2, the development of the market equilibrium simulation is an iterative process, the purpose of which is to determine the amount, timing, and location of new market entry generation that can be expected in a competitive bid-based electricity market. New entry will be determined by the perceived profitability of new generation. If market prices are high, new entrants will be attracted. If prices are low, entry will be deterred. Equilibrium is reached each year when the amount of new entry results in prices that are sufficiently high to compensate the selected new entrants for their fixed and variable costs, but not so high as to merit the entry of another new generator.

TEUS developed separate schedules of market entry generation for each scenario by modeling each year with PROSYM, and assuming the generic costs for each generator type identified by the ACIL Tasman report. Generating plants of each of the four different types (open cycle gas turbine, combined cycle gas turbine, black

[4] As noted earlier, however,

coal, brown coal) were considered. The same market equilibrium modeling approach has been used for all scenarios analyzed.

3.2.5 Forecast of Electrical Losses

After the PROSYM simulations are completed, interconnector flows are analyzed to calculate interregional losses. These losses are calculated using the quadratic loss equations applicable to each regional interface. Since the MARS model does not do an internal calculation of losses, electrical losses must be provided directly as increases in the appropriate regional loads. The losses calculated internally by PROSYM are used as load adjustments in the MARS model.

3.2.6 Simulation Outputs

The PROSYM model provides an extensive range of output information. We have relied upon the two standard output reports, the annual station revenue report and the monthly station revenue report, augmented by customized reports showing hourly load and price by region, to provide the information required to determine the profitability of new generation. The station revenue report shows the total generation (GWh), total revenue ($k), and total fuel and variable O&M cost ($k) for each generator.

Once the market entry schedule is finalized, a customized report showing interconnector flows is created and used to calculate interregional losses. Losses are handled internally by PROSYM, but must be estimated externally for incorporation into the MARS model.

3.2.7 Calculation of Energy Benefits

The market entry equilibrium balancing process was conducted separately for both the Without and With cases for each alternative project. Calculation of differences between the two simulations can capture changes in:

1. energy costs, caused by changes in the NEM's dispatch order due to increased interface capability between regions;
2. fuel costs caused by different market entry schedules;
3. voluntary load reduction; and
4. USE.

The first three items represent energy benefits and are calculated directly from the PROSYM modeling results. The USE estimated by PROSYM is not used, in deference to the more accurate estimates provided by the MARS model.

Fuel cost benefits (items 1 and 2 above) are calculated monthly by summing the fuel and variable O&M costs for all generators for the With Directlink and Without Directlink simulations and taking the difference between the two cases.

TEUS valued the changes in voluntary load reduction at the appropriate price level for each voluntary load reduction block, as discussed in Section 3.1.11.

Illustrative annual energy benefit cashflows for several scenarios are shown in Appendix 1.

3.2.8 Calculation of Deferred Market Entry Generation Benefits

Based upon the market entry schedules, the deferred capital cost benefit is calculated as avoided capital cost spending in January of the year from which the generation is deferred. The deferred O&M benefit is, similarly, the avoided O&M costs for the deferred generating units, which will occur evenly across the months in each year.

The deferred market entry generation benefits for each scenario are shown on an annual basis in Appendix 1.

4 Calculation of Reliability and Deferred Reliability Entry Generation Benefits

4.1 Inputs, Assumptions, and Information Sources

The MARS model requires detailed input data regarding hourly loads, generator capacity and availability, simplified network topology and constraints.

The primary sources of input data and constraints have been the 2003 SOO and the 2003 AIR.

Other significant sources include a February 16, 2004 load flow snapshot provided by NEMMCO, and historical hourly load information taken from the NEMMCO web site.

4.1.1 Evaluation Time Horizon

The reliability benefits were calculated using the same analysis horizon used in the calculation of the energy benefits, 2005-2044. MARS simulations were conducted for the 15 year period 2005-2019. To better approximate long run equilibrium conditions, a range of simulation termination years (2015-2019) was used. Reliability benefits (excluding the capital cost or savings of reliability entry plant) for years following each simulation termination year were replicated for the remainder of the analysis horizon. Section 3.1.1 describes the analysis horizon in more detail.

4.1.2 Inflation and Discount Rates

Section 3.1.2 describes the inflation and discount rate parameters that were used in the analysis of energy benefits. The same inflation and discount rate parameters were used in the calculation of the reliability benefits.

4.1.3 Generator Characteristics

The operating characteristics of generators modeled in MARS have been developed from the 2003 SOO and 2003 AIR, and are fully consistent with the assumptions used in the PROSYM modeling. These characteristics are listed in Appendix 2, and include:

- Location/subregion (see section 4.1.5)
- Seasonal maximum capacity (winter ratings March–November, summer ratings December–February)
- Forced outage rates
- Annual maintenance requirements
- Marginal loss factors[5].

[5] Generator capacity ratings were adjusted by the generator-specific marginal loss factor to provide input capacity ratings to the MARS model.

MARS requires maintenance to be specified as an integer number of weeks. The maintenance requirements in days/year, as identified in the IRPC Stage 1 Report[6], have been rounded to the nearest integer number of weeks/year. Annual maintenance schedules are developed by the MARS model on a regional basis considering the regional load and generation in a manner that will levelize each region's reserves over the year.

The MARS model provides the capability to represent unit outages in terms of outage states that may include partial outages as well as full outages. When the probabilities of moving from one outage state to another or outage frequency and duration data are not available, MARS imputes appropriate transition probabilities from the forced outage rates and an estimate of the number of annual outages. The IRPC Stage 1 Report does not provide outage state transition probabilities, but does provide forced outage rates (FOR) and mean time to repair (MTTR). The published forced outage rates are used directly. The number of annual outages are calculated as:

$$\text{Annual outages} = 8760 \times \text{FOR} / \text{MTTR}$$

4.1.4 Demand-Side Impacts

Voluntary load curtailment (dispatchable load) is included by region in the MARS model as generators of last resort that can be called upon to avoid or reduce the amount of USE within the NEM. The total amounts of available voluntary load reduction are calculated in the same manner as previously described in section 3.1.11, although there is no need in the reliability modeling to separate blocks by price band.

4.1.5 Network Topology and Constraints

As discussed previously, MARS is a Monte Carlo simulation model that evaluates the reliability performance of a multi-area transmission system, reflecting the operations, maintenance and forced outage characteristics of generators and the projected hourly loads of the several connected areas. The topology of the multi-area system, including the changing limits on flows between areas as augmentations are implemented or deferred is an important determinant of the reliability performance of the system.

4.1.5.1 Network Topology

The diagram in Figure 3.1 illustrates the network topology assumed in the MARS analysis. It is consistent with the five regions presently defined in the NEM, but incorporates additional detail by subdividing three of the regions into several sub-regions.

[6] NEMMCO, "IRPC Stage One Report, Proposed SANI Interconnector" *(*IRPC Stage 1 Report*)*, July 1999.

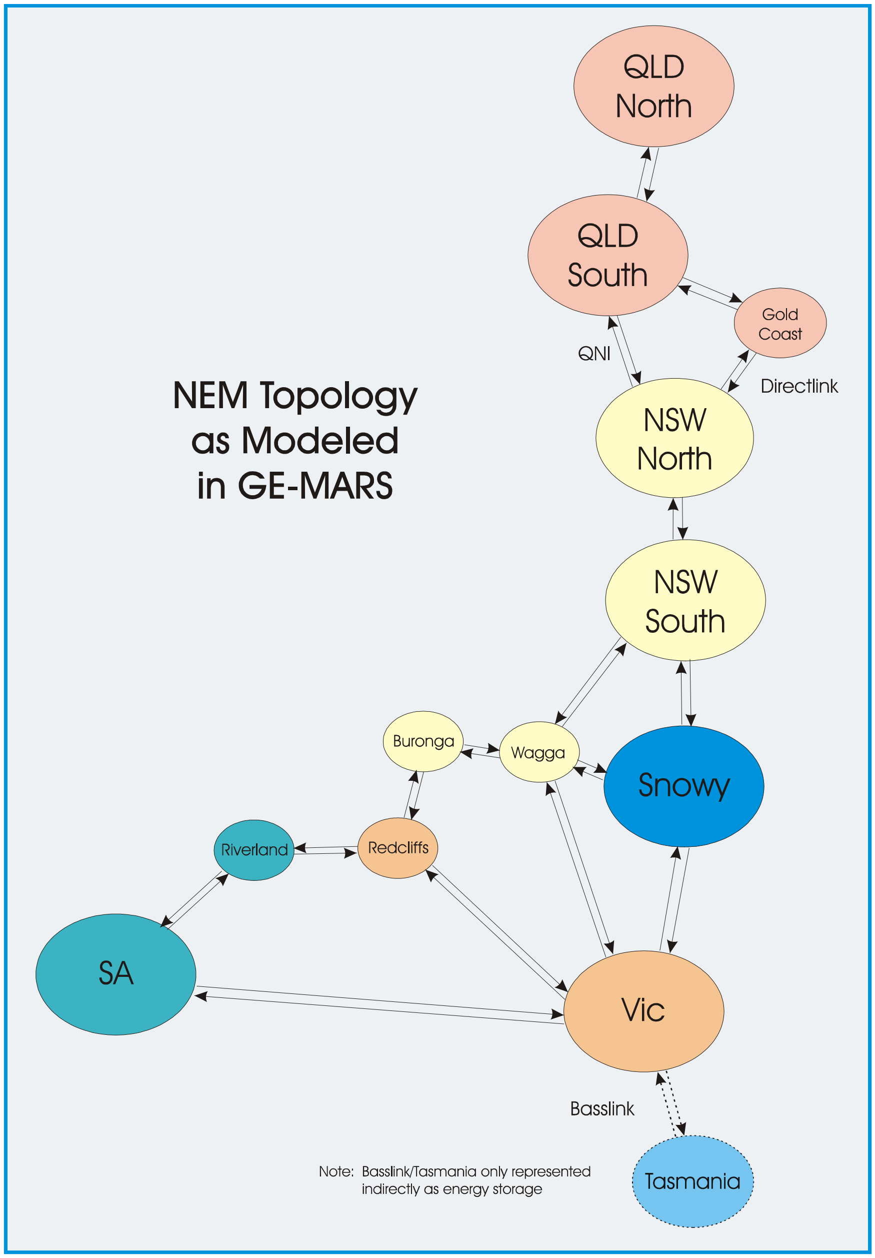

Figure 4.1

4.1.5.2 Modeling Limits in MARS

Interface limits between the five NEM regions have been published by NEMMCO in the 2003 SOO. Limits on interfaces between sub-regions that are not identified in the SOO were developed separately.

BRW has analyzed the proposed Directlink alternative projects and proposed augmentations that would otherwise be required and provided estimates of the interfaces between the northern NSW and Gold Coast sub-regions and adjacent areas. The limits provided by BRW are summarized in Tables 4.1a through 4.1i.

No Alternative Project | Medium Growth

	Interface Transfer Capability - MW									
	QLDN-QLDS		QLDS-NSWN		QLDS-GC		GC-NSWN		NSWN-NSWS	
	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction
2005	2170	2170	1125	192	805	132	0	0	870	1300
2006	2170	2170	1125	192	1059	132	0	0	870	1300
2007	2170	2170	1125	192	1059	132	0	0	870	1300
2008	2170	2170	1125	192	1059	132	0	0	870	1300
2009	2170	2170	1125	192	1059	132	0	0	870	1300
2010	2170	2170	1125	192	1059	132	0	0	870	1300
2011	2170	2170	1125	192	1059	132	0	0	870	1300
2012	2170	2170	1125	192	1059	132	0	0	870	1300
2013	2170	2170	1125	192	1059	132	0	0	870	1300
2014	2170	2170	1125	723	1059	132	0	0	1700	2560
2015	2170	2170	1125	723	1313	132	0	0	1700	2560
2016	2170	2170	1125	723	1313	132	0	0	1700	2560
2017	2170	2170	1125	723	1313	132	0	0	1700	2560
2018	2170	2170	1125	723	1313	132	0	0	1700	2560
2019	2170	2170	1125	723	1313	132	0	0	1700	2560
2020	2170	2170	1125	723	1313	132	0	0	1700	2560

Table 4.1a

Alternative Project 0, 1, 0r 2 | Medium Growth

	Interface Transfer Capability - MW									
	QLDN-QLDS		QLDS-NSWN		QLDS-GC		GC-NSWN		NSWN-NSWS	
	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction
2005	2170	2170	1125	230	805	132	125	180	870	1300
2006	2170	2170	1125	230	805	132	125	180	870	1300
2007	2170	2170	1125	230	805	132	125	180	870	1300
2008	2170	2170	1125	230	805	132	125	180	870	1300
2009	2170	2170	1125	230	805	132	125	180	870	1300
2010	2170	2170	1125	230	805	132	125	180	870	1300
2011	2170	2170	1125	230	1059	132	125	180	870	1300
2012	2170	2170	1125	230	1059	132	125	180	870	1300
2013	2170	2170	1125	230	1059	132	125	180	870	1300
2014	2170	2170	1125	230	1059	132	125	180	870	1300
2015	2170	2170	1125	230	1059	132	125	180	870	1300
2016	2170	2170	1125	230	1059	132	125	180	870	1300
2017	2170	2170	1125	761	1059	132	125	180	1700	2560
2018	2170	2170	1125	761	1059	132	125	180	1700	2560
2019	2170	2170	1125	761	1313	132	125	180	1700	2560
2020	2170	2170	1125	761	1313	132	125	180	1700	2560

Table 4.1b

Alternative Project 3 — Medium Growth

	Interface Transfer Capability - MW									
	QLDN-QLDS		QLDS-NSWN		QLDS-GC		GC-NSWN		NSWN-NSWS	
	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction
2005	2170	2170	850	230	805	132	125	180	870	1300
2006	2170	2170	850	230	805	132	125	180	870	1300
2007	2170	2170	850	230	805	132	125	180	870	1300
2008	2170	2170	850	230	1059	132	125	180	870	1300
2009	2170	2170	850	230	1059	132	125	180	870	1300
2010	2170	2170	850	230	1059	132	125	180	870	1300
2011	2170	2170	850	230	1059	132	125	180	870	1300
2012	2170	2170	850	230	1059	132	125	180	870	1300
2013	2170	2170	850	230	1059	132	125	180	870	1300
2014	2170	2170	850	761	1059	132	125	180	1700	2560
2015	2170	2170	850	761	1059	132	125	180	1700	2560
2016	2170	2170	850	761	1313	132	125	180	1700	2560
2017	2170	2170	850	761	1313	132	125	180	1700	2560
2018	2170	2170	850	761	1313	132	125	180	1700	2560
2019	2170	2170	850	761	1313	132	125	180	1700	2560
2020	2170	2170	850	761	1313	132	125	180	1700	2560

Table 4.1c

No Alternative Project — Low Growth

	Interface									
	QLDN-QLDS		QLDS-NSWN		QLDS-GC		GC-NSWN		NSWN-NSWS	
	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction
2005	2170	2170	1125	192	805	132	0	0	870	1300
2006	2170	2170	1125	192	1059	132	0	0	870	1300
2007	2170	2170	1125	192	1059	132	0	0	870	1300
2008	2170	2170	1125	192	1059	132	0	0	870	1300
2009	2170	2170	1125	192	1059	132	0	0	870	1300
2010	2170	2170	1125	192	1059	132	0	0	870	1300
2011	2170	2170	1125	192	1059	132	0	0	870	1300
2012	2170	2170	1125	192	1059	132	0	0	870	1300
2013	2170	2170	1125	192	1059	132	0	0	870	1300
2014	2170	2170	1125	192	1059	132	0	0	870	1300
2015	2170	2170	1125	723	1059	132	0	0	1700	2560
2016	2170	2170	1125	723	1059	132	0	0	1700	2560
2017	2170	2170	1125	723	1059	132	0	0	1700	2560
2018	2170	2170	1125	723	1059	132	0	0	1700	2560
2019	2170	2170	1125	723	1059	132	0	0	1700	2560
2020	2170	2170	1125	723	1059	132	0	0	1700	2560

Table 4.1d

Alternative Project 0, 1, or 2 — Low Growth

	Interface									
	QLDN-QLDS		QLDS-NSWN		QLDS-GC		GC-NSWN		NSWN-NSWS	
	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction
2005	2170	2170	1125	230	805	132	125	180	870	1300
2006	2170	2170	1125	230	805	132	125	180	870	1300
2007	2170	2170	1125	230	805	132	125	180	870	1300
2008	2170	2170	1125	230	805	132	125	180	870	1300
2009	2170	2170	1125	230	805	132	125	180	870	1300
2010	2170	2170	1125	230	805	132	125	180	870	1300
2011	2170	2170	1125	230	805	132	125	180	870	1300
2012	2170	2170	1125	230	805	132	125	180	870	1300
2013	2170	2170	1125	230	805	132	125	180	870	1300
2014	2170	2170	1125	230	1059	132	125	180	870	1300
2015	2170	2170	1125	230	1059	132	125	180	870	1300
2016	2170	2170	1125	230	1059	132	125	180	870	1300
2017	2170	2170	1125	230	1059	132	125	180	870	1300
2018	2170	2170	1125	230	1059	132	125	180	870	1300
2019	2170	2170	1125	230	1059	132	125	180	870	1300
2020	2170	2170	1125	761	1059	132	125	180	1700	2560

Table 4.1e

Alternative Project 3 — Low Growth

	Interface									
	QLDN-QLDS		QLDS-NSWN		QLDS-GC		GC-NSWN		NSWN-NSWS	
	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction
2005	2170	2170	850	230	805	132	125	180	870	1300
2006	2170	2170	850	230	805	132	125	180	870	1300
2007	2170	2170	850	230	805	132	125	180	870	1300
2008	2170	2170	850	230	805	132	125	180	870	1300
2009	2170	2170	850	230	1059	132	125	180	870	1300
2010	2170	2170	850	230	1059	132	125	180	870	1300
2011	2170	2170	850	230	1059	132	125	180	870	1300
2012	2170	2170	850	230	1059	132	125	180	870	1300
2013	2170	2170	850	230	1059	132	125	180	870	1300
2014	2170	2170	850	230	1059	132	125	180	870	1300
2015	2170	2170	850	761	1059	132	125	180	1700	2560
2016	2170	2170	850	761	1059	132	125	180	1700	2560
2017	2170	2170	850	761	1059	132	125	180	1700	2560
2018	2170	2170	850	761	1059	132	125	180	1700	2560
2019	2170	2170	850	761	1059	132	125	180	1700	2560
2020	2170	2170	850	761	1059	132	125	180	1700	2560

Table 4.1f

No Alternative Project — High Growth

	Interface									
	QLDN-QLDS		QLDS-NSWN		QLDS-GC		GC-NSWN		NSWN-NSWS	
	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction
2005	2170	2170	1125	192	805	132	0	0	870	1300
2006	2170	2170	1125	192	1059	132	0	0	870	1300
2007	2170	2170	1125	192	1059	132	0	0	870	1300
2008	2170	2170	1125	192	1059	132	0	0	870	1300
2009	2170	2170	1125	192	1059	132	0	0	870	1300
2010	2170	2170	1125	192	1313	132	0	0	870	1300
2011	2170	2170	1125	192	1313	132	0	0	870	1300
2012	2170	2170	1125	723	1313	132	0	0	1700	2560
2013	2170	2170	1125	723	1313	132	0	0	1700	2560
2014	2170	2170	1125	723	1313	132	0	0	1700	2560
2015	2170	2170	1125	723	1313	132	0	0	1700	2560
2016	2170	2170	1125	723	1313	132	0	0	1700	2560
2017	2170	2170	1125	723	1313	132	0	0	1700	2560
2018	2170	2170	1125	723	1313	132	0	0	1700	2560
2019	2170	2170	1125	723	1313	132	0	0	1700	2560
2020	2170	2170	1125	723	1313	132	0	0	1700	2560

Table 4.1g

Alternative Project 0, 1, or 2										High Growth
	Interface									
	QLDN-QLDS		QLDS-NSWN		QLDS-GC		GC-NSWN		NSWN-NSWS	
	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction
2005	2170	2170	1125	230	805	132	125	180	870	1300
2006	2170	2170	1125	230	805	132	125	180	870	1300
2007	2170	2170	1125	230	805	132	125	180	870	1300
2008	2170	2170	1125	230	1059	132	125	180	870	1300
2009	2170	2170	1125	230	1059	132	125	180	870	1300
2010	2170	2170	1125	230	1059	132	125	180	870	1300
2011	2170	2170	1125	230	1059	132	125	180	870	1300
2012	2170	2170	1125	230	1313	132	125	180	870	1300
2013	2170	2170	1125	230	1313	132	125	180	870	1300
2014	2170	2170	1125	761	1313	132	125	180	1700	2560
2015	2170	2170	1125	761	1313	132	125	180	1700	2560
2016	2170	2170	1125	761	1313	132	125	180	1700	2560
2017	2170	2170	1125	761	1313	132	125	180	1700	2560
2018	2170	2170	1125	761	1313	132	125	180	1700	2560
2019	2170	2170	1125	761	1313	132	125	180	1700	2560
2020	2170	2170	1125	761	1313	132	125	180	1700	2560

Table 4.1h

Alternative Project 3										High Growth
	Interface									
	QLDN-QLDS		QLDS-NSWN		QLDS-GC		GC-NSWN		NSWN-NSWS	
	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction	Positive Direction	Negative Direction
2005	2170	2170	850	230	805	132	125	180	870	1300
2006	2170	2170	850	230	1059	132	125	180	870	1300
2007	2170	2170	850	230	1059	132	125	180	870	1300
2008	2170	2170	850	230	1059	132	125	180	870	1300
2009	2170	2170	850	230	1059	132	125	180	870	1300
2010	2170	2170	850	230	1313	132	125	180	870	1300
2011	2170	2170	850	230	1313	132	125	180	870	1300
2012	2170	2170	850	761	1313	132	125	180	1700	2560
2013	2170	2170	850	761	1313	132	125	180	1700	2560
2014	2170	2170	850	761	1313	132	125	180	1700	2560
2015	2170	2170	850	761	1313	132	125	180	1700	2560
2016	2170	2170	850	761	1313	132	125	180	1700	2560
2017	2170	2170	850	761	1313	132	125	180	1700	2560
2018	2170	2170	850	761	1313	132	125	180	1700	2560
2019	2170	2170	850	761	1313	132	125	180	1700	2560
2020	2170	2170	850	761	1313	132	125	180	1700	2560

Table 4.1i

Limits for all other interfaces were developed using the thermal capacity of the links as represented in the summer peak load flow. Table 4.2 provides a summary of the limits used in the MARS analysis for interfaces not provided by BRW.

Summary of Additional Interface Limits				
Interface	Seasonality	Positive Limit MW	Negative Limit MW	Comment
WAG to BUR		296	296	
WAG to SNWY		1050	1050	
WAG to VIC		817	817	
BUR to RED		265	265	
SNWY to VIC		1500	748	
VIC to RED		461	461	
VIC to SA		240	100	Part of Heywood
VIC to SA2		210	175	Part of Heywood
VIC to SA3		50	25	Part of Heywood
RED to RIV		0	0	
RIV to SA		255	255	
SnoVic		1900	1100	
NSW to Snowy	March-Nov	1150	3200	
NSW to Snowy	Dec-Feb	1150	2800	
RED to RIV		220	150	Murraylink
QNI & DL North to South		1130	880	

Table 4.2

MARS provides several capabilities that allow composite multi-interface limits and dynamically changing limits to be modeled. These include, but are not limited to: (a) creating composite limits that constrain the total simultaneous flow over several interfaces to be less than or equal to a specified value; (b) allowing limits to change with time (for example, seasonal limits, or limits that grow or decline year by year); (c) different limits that apply when certain conditions are met, such as the unavailability of specific generators or area load in excess of a target level; and (d) restricting exports from an area when insufficient resources are available within the area. These techniques have been used to accurately model the interactions between Murraylink limits, SnoVic flows, and Riverland load[7]. They have not been required to model the important characteristics of Directlink and the Directlink alternatives.

The MARS modeling is an hourly simulation of the 15 year period 2005–-2019 on a pre-contingent, or “all lines in” basis. Transmission maintenance is assumed to be conducted in periods in which it would have *de minimus* reliability impacts. Only derates of the Heywood interconnector between Victoria and South Australia for electrical storm activity were modeled as transmission outages.

4.1.6 Interconnector Outages

Maintenance and forced outages on interconnectors have the potential to affect reliability in the NEM. We make the assumption that planned maintenance would be undertaken only during periods when it would not jeopardize network reliability.

[7] The modeling of Murraylink constraints is fully described in “Estimation of Murraylink Market Benefits”, a report prepared by TransEnergie US and submitted to the ACCC in October 2002 as part of Murraylink’s Application for Conversion to a Prescribed Service.

Transmission forced outage rates are typically very low, and we have assumed them to be zero, with one exception. The Heywood interconnector is frequently subject to derates of up to 50%, caused primarily by the threat of nearby electrical storm activity. A report by SAIIR[8] provides information on the size, duration, and frequency of these outages. To incorporate this information, the Heywood interconnector is modeled as three components:

- 50% of total capacity with an outage rate of 1.36% for lightning outages (VIC-SA)
- 10% of total capacity with an outage rate of 4.3% for "other" outages (VIC-SA2)
- 40% with a zero outage rate (VIC-SA3).

4.1.7 Continuation of Reserve Trader

Currently, according to the Code, NEMMCO's role as reserve trader will expire at the end of June 2005. However, TEUS has assumed that this date will be extended indefinitely.

4.1.8 Siting of New Reliability Entry Generation

Due to the perceived difficulty of siting new generation and obtaining a reliable fuel supply in certain locations, TEUS has assumed that reliability entry generation may only be added in the South Australia (excluding Riverland), Victoria (excluding Red Cliffs), Southern New South Wales, and Queensland South sub-regions.

4.1.9 Reserve Sharing

The NEM operates as an integrated system under centralized dispatch control. Therefore, generation resources in any region are assumed to be available to meet demands in any other region, subject to transfer limitations. The internal algorithm used by MARS to solve the multi-area reliability problem requires that a priority order be assigned to all regions. The priority order used for this analysis is:

Gold Coast
Northern NSW
QLD South
Southern NSW
QLD North
Buronga
Wagga
Riverland
SA (excluding Riverland)
Victoria (excluding Redcliffs)
Redcliffs
Snowy

[8] *Transmission Line Performance in South Australia & the SA Transmission Code*, South Australian Independent Industry Regulator, December 2001.

When USE occurs, the priority order could affect the region in which the USE appears, but because full reserve sharing is modeled, it will not affect the level of total system USE. The two regions connected by Directlink, Gold Coast and Northern NSW, are placed highest on the priority list to minimize the possible need to add reliability plant in regions where siting generation would be difficult or impossible. The quantification of unserved energy reliability benefits should not be affected, as it is based on changes in total system USE.

4.1.10 Chronological Load Traces

As discussed in Section 3.1.4, load traces for Queensland, New South Wales, Victoria and South Australia were created using the 2003 SOO forecast peak demand and annual energy.

The Snowy region is presumed to have generation but negligible load.

To create the other load traces for the sub-regions used in the MARS analysis, sub-regional factors were developed to allocate the total regional load in each region to each of the sub-regions on an hourly basis. For example, NSW load was proportioned out to the Buronga, Wagga, and Northern NSW and Southern NSW sub-regions. The allocation factors for Queensland and NSW were developed using a recent summer peak condition load flow file for February 16, 2004 provided by NEMMCO.

Similarly, allocation factors for the sub-regions in Victoria and South Australia were developed from a projected 2003-04 summer peak load flow file. The load flows identify the load at each bus within a region. The buses were allocated to sub-regions, and then loads were summed by sub-region. The allocation factors were calculated as the total sub-regional loads divided by total regional load.

This method preserves the regional load diversity present in the historical load data used to define the load shapes, although it may not capture any additional sub-regional load diversity that might exist outside of the summer peak hours. Constructing more detailed load traces for the sub-regions would have required access to commercially proprietary information.

Load Allocation Factors		
Region	Subregion	Allocation Factor
NSW	Buronga	0.5%
	NSWN	3.4%
	NSWS	92.2%
	Wagga	3.9%
Queensland	GC	8.1%
	QLDN	48.6%
	QLDS	43.3%
Victoria	Redcliffs	3.1%
	Vic_S	96.9%
South Australia	Riverland	2.8%
	SA_W	97.2%

Table 4.3

4.1.11 Load Uncertainty

NEMMCO and the IRPC have traditionally addressed uncertainty in load forecasts due to weather and other factors unrelated to long term economic growth by developing alternative load shapes for 10%, 50%, and 90% POE forecasts. MARS allows the impact of load uncertainty to be handled through the specification of up to 10 load uncertainty bands, their associated probabilities and load scaling factors for each band. During the chronological stochastic simulation, reliability measures are calculated each hour for each load uncertainty band (i.e. load is adjusted up or down by the appropriate scale factor for each band), and the results are weighted by the band probabilities.

For each year, the widths and probabilities for the lower five bands and the upper five bands were developed by assuming that (a) the 50% POE and 90% POE forecast peak demands defined one side of a normal distribution, and (b) the 50% POE and 10% POE forecast peak demands defined the other side of a normal distribution with a different variance. Load scaling factors were calculated for each band such that each of the five lower bands would represent 1%, 4%, 5%, 20%, and 20% of the total probability, respectively, consistent with a normal probability distribution with a variance given by the 90% POE and the 50% POE forecast.

Similarly, probabilities and widths were developed for the five upper load uncertainty bands by assuming the 50% POE and 10% POE forecast peak demands defined the upper side of a similar, but different, normal distribution.

4.1.12 Losses

The MARS model does not provide a direct means of modeling dynamic losses on interconnectors. The effect of these losses was represented by using the hourly interconnector losses projected by the appropriate PROSYM run for the same period, and adding the losses to the load of the sending region. This has the effect of forcing MARS to account for the energy lost due to electrical losses at the correct location in the grid.

4.1.13 Value of Unserved Energy

In its decision on Murraylink Transmission Company's application, the ACCC determined that, for the purpose of applying the Regulatory Test, a value equivalent to the current wholesale price cap of $10,000 per MWh should be applied as the value of unserved energy.[9]

This is a highly conservative figure given that VENCorp has undertaken a detailed study of the actual cost to end-use of supply interruptions and concludes that the value of unserved energy for the purpose of applying the Regulatory Test should be $29,600 per MWh.[10]

[9] ACCC, *Decision: Murraylink Transmission Company Application for Conversion and Maximum Allowable Revenue*, 1 October 2003, p. 86.
[10] VENCorp, *Response to Submissions: Final Report – Value of Unserved Energy to be used by VENCorp for Electricity Transmission Planning*, 23 May 2003.

For these reasons, TEUS has calculated the inter-regional market benefits for the alternative projects using a both values of unserved energy, that is, $29,600 per MWh and $10,000 per MWh. TEUS believes that $29,600 per MWh is the more accurate and appropriate value.

4.2 Methodology

4.2.1 Overall Approach

TEUS has calculated the annual reliability benefit of each of the alternative projects as the change in expected USE between the With and Without cases, multiplied by the value of unserved energy.

The reliability benefit in 2020 is assumed to apply for the remainder of the analysis horizon. In the early years, when reserves are high and USE is low, Directlink and the alternative projects make small but noticeable decreases in annual USE. Over time, the level of USE increases, and the reduction in annual USE due to Directlink is significantly greater. The total USE reliability benefit is the cumulative present worth of the stream of annual USE reduction benefits.

An accurate estimate of USE requires a sophisticated stochastic simulation approach that can explicitly address complex interconnector constraints. For that reason, TEUS selected the MARS model, a stochastic multi-area reliability simulation model that accurately captures the impacts of reserve sharing between interconnected regions with diverse load patterns and generation portfolios.

This modeling technique directly measures and values the increased reliability that Directlink provides, rather than using a shadow valuation technique such as “installed capacity margins” that attempts to (indirectly) mimic the valuation process.

TEUS simulates NEMMCO reserve trader role by reviewing the MARS estimates of USE by region and year using the market equilibrium market entry schedule developed with PROSYM. Where USE exceeds the 0.002% criteria, additional capacity is added in 50 MW increments until the criteria is achieved. The analysis is conducted iteratively to minimize the total amount of reliability plant required, recognizing the interdependence of the regions on the grid. As a modeling convenience, the addition of reliability plant is actually accomplished through load adjustments. The addition of 50 MW of reliability entry plant in a sub-region is simulated by lowering the sub-region’s load in all hours by 50 MW. Reliability plant is valued at the cost of OCGT generation, as described in the ACIL Tasman Report.

4.2.2 Required Simulations

Specifically, TEUS’s modeling has been accomplished in several steps:

1. With and Without balanced equilibrium market entry schedules are developed as part of the energy benefits analysis using the PROSYM model.

2. The MARS model is run using the competitive equilibrium market entry planting schedules for two cases, With and Without the interconnection.

3. The USE in sub-regions is summed by region for the With and Without Cases, and tested for compliance with the 0.002% USE criteria. Reliability plant is added in 50 MW increments where necessary, and the simulations are repeated until every region satisfies the criteria in every year.

4. The impact of Directlink or the Directlink alternative on USE is calculated by subtracting month by month, the USE in the With case from the USE in the Without Case. Note that USE in the Without case will not necessarily be greater than USE in the With case, due to differences in market entry in the two cases.

The MARS analysis is used to calculate Directlink's reliability benefits in the manner described above for the 2005–2019 period. By 2019, TEUS believes the system will have converged to a long run economic equilibrium, or, because of the lumpy nature of market entry generation, be oscillating around an equilibrium condition over a period of several years. Even though reliability entry plant is added in relatively small 50 MW increments, the need for reliability entry generation is largely dictated by the amounts and locations of market entry generation determined through the PROSYM market simulations. USE levels in years beyond the simulation termination year are assumed to repeat the pattern exhibited in the 12 months of the termination year.

4.2.3 Simulation Outputs

The MARS model calculates several standard reliability statistics for each region in the multi-area system being studied, including the loss of load expectation (LOLE) in days/year and hours/year, loss of energy expectation (LOEE, referred to in this report as unserved energy or USE), loss of load frequency (in outages/year), and loss of load duration (in hours/outage).

TEUS selected unserved energy (LOEE or USE) as the most appropriate measure of reliability impacts because:

- It is consistent with the metrics used by the NECA Reliability Panel in its reviews of NEM reliability standards.
- It directly captures impacts across the entire NEM consistently, without requiring adjustments to make outage frequency in a region with relatively large load, such as NSW, comparable to the outage frequency in a smaller load region, such as SA.
- It provides a direct indication of the magnitude of the customer impact of reliability problems.

The MARS simulation runs chronologically on an hourly basis, and reliability statistics are reported on a monthly and annual basis.

4.2.4 Calculation of Benefits

The difference in reliability entry generation additions is valued at the capital cost and fixed O&M cost of new Open Cycle Gas Turbines, in much the same manner as differences in market entry generation are valued.

The difference in expected USE between the With and Without cases is calculated, based on MARS simulations that estimate the residual unserved energy after incorporating both the market entry and reliability entry schedules for each. The residual USE will be small (by definition, less than or equal to 0.002% of annual energy demand). The difference in the residual USE is calculated month by month, and is valued at the value of unserved energy (assumed to be VoLL, or $10,000/MWh for most scenarios).

The total reliability benefit is the sum of the deferred reliability entry generation benefit and the residual USE benefit. The value of the total reliability benefit is the cumulative present worth of the monthly estimated difference in residual USE and the difference in reliability entry generation cost.

Figure 4.2 shows monthly estimates of USE for the LRMC Alternative 1 Medium Growth scenario. The seasonal patterns is clearly visible, as well as a long term trend that increases slowly until 2012 when load increases start to drive market entry. After 2012 the pattern of USE approximately levels off, where year to year differences are primarily cause by the lumpy nature of market entry generation additions.

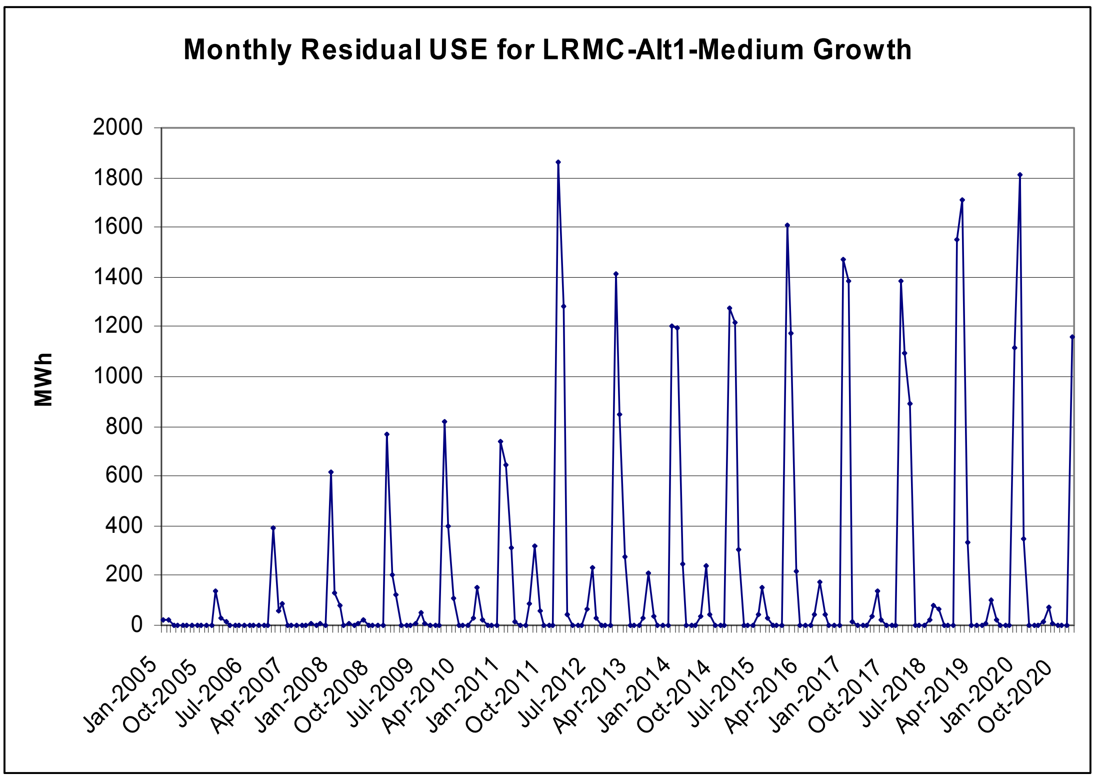

Figure 4.2

5 Scenarios and Results

5.1 Description of Scenarios

TEUS has evaluated a number of scenarios. The scenarios represent various combinations of important assumptions that drive the estimated inter-regional market benefits:

- Alternative projects
- Low, medium and high economic growth
- LRMC and SRMC generator bidding strategies
- Value of unserved energy
- Long run marginal cost of generation
- Discount rate

5.1.1 Credible Market Development Scenarios

As required by the Regulatory Test, TEUS has estimated the inter-regional market benefits of the Alternative Projects under a number of credible market development scenarios. Each Alternative Project has been evaluated under four specific different scenarios which, taken together, we consider to be our "base case" scenarios:

- LRMC/Medium Economic Growth
- SRMC/Medium Economic Growth
- LRMC/Low Economic Growth
- LRMC/High Economic Growth

Each of these base case scenarios is based on a 9% discount rate and values of unserved energy of both $10,000 per MWh and $29,600 per MWh. As discussed in Sections 3.1.7.1 and 3.1.7.2, the LRMC and SRMC bidding strategies were developed using information published in the ACIL Tasman report. All base case scenarios incorporate the operation of Basslink, and the retirement of Swanbank B (480 MW) at the end of Summer 2010/11. A complete summary of generator characteristics in included in Appendix 2, and is discussed more generally in Section 3.1.

As market entry of new generation is driven largely by price and demand, each of the base case scenarios will lead to different amounts and timing of new generation.

5.1.2 Sensitivity Testing

To test the robustness of the scenario findings, TEUS has performed sensitivity testing to examine the impact of discount rates on the inter-regional market benefits of the Directlink alternative project. The specific sensitivities tested are:

- Discount rates of 7% and 11%

TEUS has not evaluated all combinations of each assumption. Instead, limited specific cases were analyzed to identify the preferred alternative project. Further sensitivity testing was then completed to fully explore the inter-regional market benefits this alternative would provide. Table 5.1 summarizes the specific scenarios and sensitivities examined.

Base Case Scenarios				
Bidding Strategy	Economic Growth	Discount Rate	Value USE	Market Entry Costs
LRMC	Medium	9%	10000	LRMC
SRMC	Medium	9%	10000	LRMC
LRMC	Low	9%	10000	LRMC
LRMC	High	9%	10000	LRMC
Sensitivity Analyses				
LRMC	Medium	7%	10000	LRMC
SRMC	Medium	7%	10000	LRMC
LRMC	Low	7%	10000	LRMC
LRMC	High	7%	10000	LRMC
LRMC	Medium	11%	10000	LRMC
SRMC	Medium	11%	10000	LRMC
LRMC	Low	11%	10000	LRMC
LRMC	High	11%	10000	LRMC
LRMC	Medium	9%	29600	LRMC
SRMC	Medium	9%	29600	LRMC
LRMC	Low	9%	29600	LRMC
LRMC	High	9%	29600	LRMC
LRMC	Medium	7%	29600	LRMC
SRMC	Medium	7%	29600	LRMC
LRMC	Low	7%	29600	LRMC
LRMC	High	7%	29600	LRMC
LRMC	Medium	11%	29600	LRMC
SRMC	Medium	11%	29600	LRMC
LRMC	Low	11%	29600	LRMC
LRMC	High	11%	29600	LRMC

Table 5.1

5.2 Summary of Results

Table 5.2 below provides the cumulative present worth at January 1, 2005 of inter-regional market benefits for all evaluated scenarios. Table 5.2 below provides the cumulative present worth at January 1, 2005 of inter-regional market benefits for all evaluated scenarios. These are the benefits that each alternative project would provide from January 1, 2005 to December 31, 2044.

The annual undiscounted benefit cash flows leading to these cumulative present worth results are provided in Appendix 1.

Summary of Inter-Regional Market Benefits

9%		$10,000 Value of USE: Results (Ave of Termination in Yrs 2015-2019)			$29,600 Value of USE: Results (Ave of Termination in Yrs 2015-2019)		
Alternative	Bidding	High	Med	Low	High	Med	Low
0, 1 and 2	LRMC	156,920	112,327	68,886	146,587	111,328	66,189
0, 1 and 2	SRMC		33,613			63,964	
3	LRMC	125,940	88,177	89,431	76,416	71,969	86,859
3	SRMC		11,722			21,731	

7%		$10,000 Value of USE: Results (Ave of Termination in Yrs 2015-2019)			$29,600 Value of USE: Results (Ave of Termination in Yrs 2015-2019)		
Alternative	Bidding	High	Med	Low	High	Med	Low
0, 1 and 2	LRMC	183,444	103,322	46,330	166,352	96,984	38,365
0, 1 and 2	SRMC		15,891			54,556	
3	LRMC	119,128	73,130	74,373	49,616	45,636	66,952
3	SRMC		(13,469)			(4,051)	

11%		$10,000 Value of USE: Results (Ave of Termination in Yrs 2015-2019)			$29,600 Value of USE: Results (Ave of Termination in Yrs 2015-2019)		
Alternative	Bidding	High	Med	Low	High	Med	Low
0, 1 and 2	LRMC	137,408	114,240	78,663	131,715	116,838	79,542
0, 1 and 2	SRMC		44,518			69,467	
3	LRMC	126,787	94,431	93,792	90,899	85,803	94,517
3	SRMC		27,751			38,166	

Table 5.2

5.3 Commentary

The inter-regional market benefits attributable to Alternative 0, 1, 2, and 3, which would provide comparable capabilities, derive principally from three sources – 1) a more efficient dispatch of existing generation, and 2) reserve sharing that allows reliability entry plant to be permanently deferred.

A simple PROSYM analysis indicates that, all other things being equal, a more efficient dispatch provides a benefit of approximately $40m over the period 2005-2044. A separate straightforward spreadsheet analysis indicates the cumulative present worth of permanently deferring 100 MW of reliability entry plant is approximately $50m.

These two benefits taken by themselves (i.e. ignoring the impacts of deferred entry and changes in unserved energy) amount to $90m CPW, and provide a reasonability check on the inter-regional market benefits that TEUS has estimated for the Directlink alternatives. The simple analyses make it clear that, after allowing for the impacts of market entry changes, market benefits in the range of $80-120m are certainly credible and reasonable.

The modeling results indicate that Alternative 3 provides lower inter-regional market benefits than Alternatives 0, 1, and 2. Two factors drive these differences. First, Alternative 3 uses AC technology, while Alternatives 0, 1, and 2 used HVDC technology. The two technologies have different loss functions, which lead to slight differences in generation dispatch, market prices, and ultimately in market entry schedules. Second, the deferral period for the various intra-regional augmentations is shorter for Alternative 3 than for Alternatives 0, 1, and 2. Changes in deferral periods causes changes over time in the subregional interface limits. Along with the different market entry schedule, this affects the timing and location of reliability entry plant and residual unserved energy. Together, these factors result in lower inter-regional market benefits for Alternative Project 3.

TEUS notes that the relatively large size of market entry plants as a percentage of the total market has several consequences to the analysis. First, achieving a precise equilibrium in any specific year becomes rather improbable. Second, the capital cost and continuing energy impacts caused by the addition of a large plant in the final simulated year can have significant impacts on the estimated benefits because the termination year results are extrapolated to 2044. Averaging the results of a range of termination years mitigates these concerns and allows an equilibrium result to be estimated, even when it has not been precisely simulated.

TEUS found the inter-regional market benefits for most of the alternatives to be less sensitive to the value of unserved energy than originally anticipated. A review of the results shows that, once the 0.002% USE reliability criteria is met by the addition of appropriate amounts of reliability entry plant, there is little USE left to value at either $10,000 per MWh or $29,600 per MWh. One might ask if the 0.002% criteria should change to reflect alternative estimates of the value of USE. However, TEUS did not address this question.

Variations in the discount rate had different impacts for the different alternative projects, due to the timing of positive and negative cashflows stemming from different market entry schedules. Alternatives 0, 1 and 2 were relatively insensitive, particularly in scenarios based on LRMC bidding. Alternative 3's benefits were more heavily influenced by discount rate, particularly when using SRMC bidding.

Appendix 1: Results Detail

This appendix therefore provides annual undiscounted inter-regional market benefits cash flow detail for the 40-year study horizon 2005–2044, based on a 2019 simulation termination year for Alternatives 0, 1 or 2 and Alternative 3 under LRMC bidding, medium economic growth, and $10,000 per MWh value of USE.

Medium Economic Growth Case - Simulation Termination Year 2019 Value of USE 10000 - Discount Rate 0.09 Alternative 0,1, or 2 Gross Market Benefit Annual Cashflow							
Year	Energy Savings	Merchant Entry Capital Deferral	Avoided Merchant Entry O&M	Reliability Benefit	RE Capital	RE O&M	Total
2005	689	0	0	2707	0	0	3396
2006	1683	0	0	5424	0	0	7107
2007	2839	0	0	2022	80855	1617	87333
2008	4491	0	0	350	26952	2156	33949
2009	2873	0	0	-446	0	2156	4583
2010	2761	0	0	4002	-107807	0	-101044
2011	2100	53903	1078	-3997	53903	1078	108066
2012	-3851	161710	4312	-3350	-161710	-2156	-5045
2013	1428	-53903	3234	-1740	26952	-1617	-25646
2014	7016	-53903	2156	-4237	53903	-539	4396
2015	1587	-107807	0	-405	53903	539	-52182
2016	-44802	463568	16063	-4483	0	539	430885
2017	-71877	398884	24796	1607	-161710	-2695	189005
2018	2262	-862453	0	-1107	188662	1078	-671559
2019	2761	107807	2156	-1089	-53903	0	57731
2020	2761	0	2156	-1089	0	0	3828
2021	2761	0	2156	-1089	0	0	3828
2022	2761	0	2156	-1089	0	0	3828
2023	2761	0	2156	-1089	0	0	3828
2024	2761	0	2156	-1089	0	0	3828
2025	2761	0	2156	-1089	0	0	3828
2026	2761	0	2156	-1089	0	0	3828
2027	2761	0	2156	-1089	0	0	3828
2028	2761	0	2156	-1089	0	0	3828
2029	2761	0	2156	-1089	0	0	3828
2030	2761	0	2156	-1089	0	0	3828
2031	2761	0	2156	-1089	0	0	3828
2032	2761	0	2156	-1089	0	0	3828
2033	2761	0	2156	-1089	0	0	3828
2034	2761	0	2156	-1089	0	0	3828
2035	2761	0	2156	-1089	0	0	3828
2036	2761	0	2156	-1089	0	0	3828
2037	2761	0	2156	-1089	0	0	3828
2038	2761	0	2156	-1089	0	0	3828
2039	2761	0	2156	-1089	0	0	3828
2040	2761	0	2156	-1089	0	0	3828
2041	2761	0	2156	-1089	0	0	3828
2042	2761	0	2156	-1089	0	0	3828
2043	2761	0	2156	-1089	0	0	3828
2044	2761	0	2156	-1089	0	0	3828

Medium Economic Growth Case - Simulation Termination Year 2019 Value of USE 10000 - Discount Rate 0.09 Alternative 3 Gross Market Benefit Annual Cashflow							
Year	Energy Savings	Merchant Entry Capital Deferral	Avoided Merchant Entry O&M	Reliability Benefit	RE Capital	RE O&M	Total
2005	527	0	0	2694	0	0	3221
2006	1511	0	0	5430	0	0	6941
2007	2657	0	0	1987	80855	1617	87116
2008	4290	0	0	302	26952	2156	33699
2009	2649	0	0	-545	0	2156	4260
2010	2475	0	0	3359	-107807	0	-101972
2011	1829	53903	1078	-3462	26952	539	80840
2012	-4068	161710	4312	-3004	-161710	-2695	-5454
2013	1174	-53903	3234	-2396	53903	-1617	395
2014	6819	-53903	2156	-4686	26952	-1078	-23741
2015	1331	-107807	0	-2290	80855	539	-27371
2016	-45012	463568	16063	-5390	-26952	0	402277
2017	-72072	398884	24796	-1923	-134758	-2695	212232
2018	2111	-862453	0	314	134758	0	-725270
2019	2634	107807	2156	-3337	-26952	-539	81769
2020	2634	0	2156	-3337	0	-539	914
2021	2634	0	2156	-3337	0	-539	914
2022	2634	0	2156	-3337	0	-539	914
2023	2634	0	2156	-3337	0	-539	914
2024	2634	0	2156	-3337	0	-539	914
2025	2634	0	2156	-3337	0	-539	914
2026	2634	0	2156	-3337	0	-539	914
2027	2634	0	2156	-3337	0	-539	914
2028	2634	0	2156	-3337	0	-539	914
2029	2634	0	2156	-3337	0	-539	914
2030	2634	0	2156	-3337	0	-539	914
2031	2634	0	2156	-3337	0	-539	914
2032	2634	0	2156	-3337	0	-539	914
2033	2634	0	2156	-3337	0	-539	914
2034	2634	0	2156	-3337	0	-539	914
2035	2634	0	2156	-3337	0	-539	914
2036	2634	0	2156	-3337	0	-539	914
2037	2634	0	2156	-3337	0	-539	914
2038	2634	0	2156	-3337	0	-539	914
2039	2634	0	2156	-3337	0	-539	914
2040	2634	0	2156	-3337	0	-539	914
2041	2634	0	2156	-3337	0	-539	914
2042	2634	0	2156	-3337	0	-539	914
2043	2634	0	2156	-3337	0	-539	914
2044	2634	0	2156	-3337	0	-539	914

Appendix 2: Characteristics of Existing and Committed Generation

Generator	Region	Summer	Winter	Assumed In-Service	Assumed Retire Date	Marginal Loss Factor	FOR	Annual Days of Maintenance	Mean time to Repair	SRMC Bid	LRMC Bid
Anglesea	VIC_S	155	160	1/1/2000	12/31/2099	1.0133	0.0186	10	24	6.29	26.29
Bairnsdale	VIC_S	70	92	1/1/2000	12/31/2099	0.9671	0.0115	0	24	45.30	65.30
Barcaldine	QLD	53	55	1/1/2000	12/31/2099	0.9730	0.0446	0	34	67.49	87.49
Barron Gorge 1	QLD	30	30	1/1/2000	12/31/2099	1.1831	0.0012	0	24	NA	NA
Barron Gorge 2	QLD	30	30	1/1/2000	12/31/2099	1.1831	0.0012	0	24	NA	NA
Bayswater 1	NSW_N	700	700	1/1/2000	12/31/2099	0.9538	0.0261	17	37	12.04	32.04
Bayswater 2	NSW_N	700	700	1/1/2000	12/31/2099	0.9538	0.0261	17	37	12.04	32.04
Bayswater 3	NSW_N	700	700	1/1/2000	12/31/2099	0.9538	0.0261	17	37	12.04	32.04
Bayswater 4	NSW_N	700	700	1/1/2000	12/31/2099	0.9538	0.0261	17	37	12.04	32.04
Bendeela	NSW_N	80	80	1/1/2000	12/31/2099	1.0677	0.0117	0	37	NA	NA
Callide A 1	QLD	30	30	3/1/2005	12/31/2099	0.9187	0.05	19	37	13.27	33.27
Callide A 2	QLD	30	30	3/1/2005	12/31/2099	0.9187	0.05	19	37	13.27	33.27
Callide A 3	QLD	30	30	3/1/2005	12/31/2099	0.9187	0.05	19	37	13.27	33.27
Callide A 4	QLD	30	30	3/1/2005	12/31/2099	0.9187	0.05	19	37	13.27	33.27
Callide B 1	QLD	350	350	1/1/2000	12/31/2099	0.9162	0.05	19	37	11.88	31.88
Callide B 3	QLD	350	350	1/1/2000	12/31/2099	0.9162	0.05	19	37	11.88	31.88
Callide C 3	QLD	420	420	1/1/2000	12/31/2099	0.9238	0.05	19	37	11.88	31.88
Callide C 4	QLD	420	420	1/1/2000	12/31/2099	0.9238	0.05	19	37	11.88	31.88
Collinsville A 1	QLD	30	30	1/1/2000	12/31/2099	1.0740	0.05	19	37	17.49	37.49
Collinsville A 2	QLD	30	30	1/1/2000	12/31/2099	1.0740	0.05	19	37	17.49	37.49
Collinsville A 3	QLD	30	30	1/1/2000	12/31/2099	1.0740	0.05	19	37	17.49	37.49
Collinsville A 4	QLD	30	30	1/1/2000	12/31/2099	1.0740	0.05	19	37	17.49	37.49
Collinsville B	QLD	65	65	1/1/2000	12/31/2099	1.0740	0.05	19	37	17.49	37.49
Dry Creek 1	SA_W	39	49	1/1/2000	12/31/2099	1.0036	0.0446	0	34	80.35	100.35
Dry Creek 2	SA_W	39	49	1/1/2000	12/31/2099	1.0036	0.0446	0	34	80.35	100.35
Dry Creek 3	SA_W	39	49	1/1/2000	12/31/2099	1.0036	0.0446	0	34	80.35	100.35
Eraring 1	NSW_N	660	660	1/1/2000	12/31/2099	0.9826	0.0261	17	37	14.84	34.84
Eraring 2	NSW_N	660	660	1/1/2000	12/31/2099	0.9826	0.0261	17	37	14.84	34.84
Eraring 3	NSW_N	660	660	1/1/2000	12/31/2099	0.9852	0.0261	17	37	14.84	34.84
Eraring 4	NSW_N	660	660	1/1/2000	12/31/2099	0.9852	0.0261	17	37	14.84	34.84
Gladstone 1	QLD	280	280	1/1/2000	12/31/2099	0.9548	0.05	19	37	14.85	34.85
Gladstone 2	QLD	280	280	1/1/2000	12/31/2099	0.9548	0.05	19	37	14.85	34.85
Gladstone 3	QLD	280	280	1/1/2000	12/31/2099	0.9548	0.05	19	37	14.85	34.85
Gladstone 4	QLD	280	280	1/1/2000	12/31/2099	0.9548	0.05	19	37	14.85	34.85
Gladstone 5	QLD	280	280	1/1/2000	12/31/2099	0.9548	0.05	19	37	14.85	34.85
Gladstone 6	QLD	280	280	1/1/2000	12/31/2099	0.9548	0.05	19	37	14.85	34.85
Guthega	SNOWY	60	60	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Hallett	SA_W	153	185	1/1/2000	12/31/2099	0.9972	0.0446	0	34	80.35	100.35
Hazelwood 1	VIC_S	185	205	1/1/2000	12/31/2099	0.9617	0.0186	10	24	2.15	22.15
Hazelwood 2	VIC_S	185	205	1/1/2000	12/31/2099	0.9617	0.0186	10	24	2.15	22.15
Hazelwood 3	VIC_S	216	220	1/1/2000	12/31/2099	0.9617	0.0186	10	24	2.15	22.15
Hazelwood 4	VIC_S	216	220	1/1/2000	12/31/2099	0.9617	0.0186	10	24	2.15	22.15
Hazelwood 5	VIC_S	216	220	1/1/2000	12/31/2099	0.9617	0.0186	10	24	2.15	22.15
Hazelwood 6	VIC_S	216	220	1/1/2000	12/31/2099	0.9617	0.0186	10	24	2.15	22.15
Hazelwood 7	VIC_S	216	220	1/1/2000	12/31/2099	0.9617	0.0186	10	24	2.15	22.15
Hazelwood 8	VIC_S	216	220	1/1/2000	12/31/2099	0.9617	0.0186	10	24	2.15	22.15
Hume-NSW	NSW_N	29	29	1/1/2000	12/31/2099	1.0095	0	0	0	NA	NA
Hume-Vic	VIC_S	29	29	1/1/2000	12/31/2099	1.0038	0	0	0	NA	NA
Hunter Valley 1	NSW_N	44	51	1/1/2000	12/31/2099	0.9585	0.0117	0	37	233.05	253.05
Hunter Valley 2	NSW_N	0	0	1/1/2000	12/31/2099	0.9585	0.0117	0	37	233.05	253.05
Jerralang A 1	VIC_S	52	58	1/1/2000	12/31/2099	0.9570	0.0115	0	24	51.68	71.68
Jerralang A 2	VIC_S	52	58	1/1/2000	12/31/2099	0.9570	0.0115	0	24	51.68	71.68
Jerralang A 3	VIC_S	52	58	1/1/2000	12/31/2099	0.9570	0.0115	0	24	51.68	71.68
Jerralang A 4	VIC_S	52	58	1/1/2000	12/31/2099	0.9570	0.0115	0	24	51.68	71.68
Jerralang B 1	VIC_S	75	85	1/1/2000	12/31/2099	0.9570	0.0115	0	24	51.68	71.68
Jerralang B 2	VIC_S	75	85	1/1/2000	12/31/2099	0.9570	0.0115	0	24	51.68	71.68
Jerralang B 3	VIC_S	75	85	1/1/2000	12/31/2099	0.9570	0.0115	0	24	51.68	71.68
Kangaroo Valley 1	NSW_N	80	80	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Kangaroo Valley 2	NSW_N	80	80	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Kareeya 1	QLD	18	18	1/1/2000	12/31/2099	NA	0.0012	0	24	NA	NA
Kareeya 2	QLD	18	18	1/1/2000	12/31/2099	NA	0.0012	0	24	NA	NA
Kareeya 3	QLD	18	18	1/1/2000	12/31/2099	NA	0.0012	0	24	NA	NA
Kareeya 4	QLD	18	18	1/1/2000	12/31/2099	NA	0.0012	0	24	NA	NA
Ladbroke Grove 1	SA_W	30	40	1/1/2000	12/31/2099	0.9626	0.0444	0	24	32.20	52.20
Ladbroke Grove 2	SA_W	30	40	1/1/2000	12/31/2099	0.9626	0.0444	0	24	32.20	52.20
Liddell 1	NSW_N	515	515	1/1/2000	12/31/2099	0.9549	0.0261	17	37	13.13	33.13
Liddell 2	NSW_N	515	515	1/1/2000	12/31/2099	0.9549	0.0261	17	37	13.13	33.13
Liddell 3	NSW_N	515	515	1/1/2000	12/31/2099	0.9549	0.0261	17	37	13.13	33.13
Liddell 4	NSW_N	515	515	1/1/2000	12/31/2099	0.9549	0.0261	17	37	13.13	33.13

Generator	Region	Summer	Winter	Assumed In-Service	Assumed Retire Date	Marginal Loss Factor	FOR	Annual Days of Maintenance	Mean time to Repair	SRMC Bid	LRMC Bid
Loy Yang A 1	VIC_S	530	560	1/1/2000	12/31/2099	0.9636	0.0186	10	24	1.99	21.99
Loy Yang A 2	VIC_S	490	510	1/1/2000	12/31/2099	0.9636	0.0186	10	24	1.99	21.99
Loy Yang A 3	VIC_S	510	530	1/1/2000	12/31/2099	0.9636	0.0186	10	24	1.99	21.99
Loy Yang A 4	VIC_S	500	510	1/1/2000	12/31/2099	0.9636	0.0186	10	24	1.99	21.99
Loy Yang B 1	VIC_S	500	520	1/1/2000	12/31/2099	0.9636	0.0186	10	24	5.22	25.22
Loy Yang B 2	VIC_S	505	520	1/1/2000	12/31/2099	0.9636	0.0186	10	24	5.22	25.22
Mackay GT	QLD	30	33	1/1/2000	12/31/2099	1.0926	0.0446	0	34	267.62	287.62
Middle Ridge	QLD	44	52	1/1/1999	12/31/1999	0.9872	0.0446	0	34	224.00	244.00
Millmerran 1	QLD	426	431	1/1/2000	12/31/2099	0.9475	0.05	19	37	7.81	27.81
Millmerran 2	QLD	426	431	1/1/2000	12/31/2099	0.9475	0.05	19	37	7.81	27.81
Mintaro	SA_W	70	88	1/1/2000	12/31/2099	0.9853	0.0446	0	34	80.35	100.35
Morwell A 1	VIC_S	57	60	1/1/2000	12/31/2099	0.9574	0.0186	10	24	9.00	29.00
Morwell B	VIC_S	30	33	1/1/2000	12/31/2099	0.9574	0.0186	10	24	9.00	29.00
Morwell C	VIC_S	57	60	1/1/2000	12/31/2099	0.9574	0.0186	10	24	9.00	29.00
Mt Piper 1	NSW_N	660	660	1/1/2000	12/31/2099	0.9682	0.0261	17	37	12.46	32.46
Mt Piper 2	NSW_N	660	660	1/1/2000	12/31/2099	0.9682	0.0261	17	37	12.46	32.46
Mt Stuart 1	QLD	144	147	1/1/2000	12/31/2099	1.1764	0.0446	0	34	267.62	287.62
Mt Stuart 2	QLD	144	147	1/1/2000	12/31/2099	1.1764	0.0446	0	34	267.62	287.62
Munmorah 3	NSW_N	300	300	1/1/2000	12/31/2099	0.9921	0.0261	17	37	15.99	35.99
Munmorah 4	NSW_N	300	300	1/1/2000	12/31/2099	0.9921	0.0261	17	37	15.99	35.99
Murray 1-01	SNOWY	95	95	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Murray 1-02	SNOWY	95	95	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Murray 1-03	SNOWY	95	95	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Murray 1-04	SNOWY	95	95	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Murray 1-05	SNOWY	95	95	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Murray 1-06	SNOWY	95	95	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Murray 1-07	SNOWY	95	95	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Murray 1-08	SNOWY	95	95	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Murray 1-09	SNOWY	95	95	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Murray 1-10	SNOWY	95	95	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Murray 2-01	SNOWY	137.5	137.5	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Murray 2-02	SNOWY	137.5	137.5	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Murray 2-03	SNOWY	137.5	137.5	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Murray 2-04	SNOWY	137.5	137.5	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Newport	VIC_S	475	510	1/1/2000	12/31/2099	0.9911	0.0115	10	24	41.32	61.32
Northern SA 1	SA_W	260	265	1/1/2000	12/31/2099	0.9804	0.0235	32	39	16.03	36.03
Northern SA 2	SA_W	260	265	1/1/2000	12/31/2099	0.9804	0.0235	32	39	16.03	36.03
Oakey 1	QLD	138	160	1/1/2000	12/31/2099	0.9888	0.0446	0	34	80.35	100.35
Oakey 2	QLD	138	160	1/1/2000	12/31/2099	0.9888	0.0446	0	34	80.35	100.35
Osborne	SA_W	175	190	1/1/2000	12/31/2000	0.9993	0.0235	32	39	31.49	51.49
Osborne A	SA_W	175	190	1/1/2000	12/31/2099	0.9993	0.0235	32	39	31.49	51.49
Pelican Point 1	SA_W	225	245	1/1/2000	12/31/2099	0.9986	0.0444	0	24	27.58	47.58
Pelican Point 2	SA_W	225	245	1/1/2000	12/31/2099	0.9986	0.0444	0	24	27.58	47.58
Pelican Point 3	SA_W	0	0	1/1/2000	12/31/2099	0.9986	0.0444	0	24	27.58	47.58
Playford 1	SA_W	60	60	1/1/2000	12/31/2099	0.9761	0.0446	32	34	23.16	43.16
Playford 2	SA_W	60	60	1/1/2000	12/31/2099	0.9761	0.0446	32	34	23.16	43.16
Playford 3	SA_W	60	60	1/1/2000	12/31/2099	0.9761	0.0446	32	34	23.16	43.16
Playford 4	SA_W	60	60	1/1/2000	12/31/2099	0.9761	0.0446	32	34	23.16	43.16
Port Lincoln 1	SA_W	38	48	1/1/2000	3/1/2007	0.9989	0.0446	0	34	267.62	287.62
Port Lincoln 2	SA_W	40	50	3/1/2007	12/31/2099	0.9989	0.0446	0	34	267.62	287.62
Quarantine	SA_W	88	98	1/1/1999	12/31/2099	0.9969	0.0446	0	34	60.60	80.60
Redbank	NSW_N	151	151	1/1/2000	12/31/2099	0.9595	0.0261	17	37	9.33	29.33
Roma 7	QLD	31	34	1/1/2000	12/31/2099	0.9694	0.0012	0	24	51.53	71.53
Roma 8	QLD	31	34	1/1/2000	12/31/2099	0.9694	0.0012	0	24	51.53	71.53
Shoalhaven 1	NSW_N	80	80	1/1/2050	12/31/2099	NA	0.0117	0	37	NA	NA
Shoalhaven 2	NSW_N	80	80	1/1/2050	12/31/2099	NA	0.0117	0	37	NA	NA
Shoalhaven 3	NSW_N	40	40	1/1/2050	12/31/2099	NA	0.0117	0	37	NA	NA
Shoalhaven 4	NSW_N	40	40	1/1/2050	12/31/2099	NA	0.0117	0	37	NA	NA
Smithfield	NSW_N	160	160	1/1/2000	12/31/2099	1.0021	0.0261	17	37	35.74	55.74
Snuggery 1	SA_W	18	21	1/1/2000	3/1/2012	NA	0.0446	0	34	NA	NA
Snuggery 2	SA_W	18	21	1/1/2000	12/31/2099	NA	0.0446	0	34	NA	NA
Snuggery 3	SA_W	18	21	1/1/2000	12/31/2099	NA	0.0446	0	34	NA	NA
Somerton	VIC_S	123	157	1/1/2000	12/31/2099	1.0000	0.0115	0	24	56.01	76.01
Stanwell 1	QLD	350	350	1/1/2000	12/31/2099	0.9473	0.05	19	37	13.16	33.16
Stanwell 2	QLD	350	350	1/1/2000	12/31/2099	0.9473	0.05	19	37	13.16	33.16

Generator	Region	Summer	Winter	Assumed In-Service	Assumed Retire Date	Marginal Loss Factor	FOR	Annual Days of Maintenance	Mean time to Repair	SRMC Bid	LRMC Bid
Stanwell 3	QLD	350	350	1/1/2000	12/31/2099	0.9473	0.05	19	37	13.16	33.16
Stanwell 4	QLD	350	350	1/1/2000	12/31/2000	0.9473	0.05	19	37	13.16	33.16
Southern Hydro	VIC_S	382	382	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Swanbank B 1	QLD	120	125	1/1/2000	3/1/2011	0.9999	0.05	19	37	20.15	40.15
Swanbank B 2	QLD	120	125	1/1/2000	3/1/2011	0.9999	0.05	19	37	20.15	40.15
Swanbank B 3	QLD	120	125	1/1/2000	3/1/2011	0.9999	0.05	19	37	20.15	40.15
Swanbank B 4	QLD	120	125	1/1/2000	3/1/2011	0.9999	0.05	19	37	20.15	40.15
Swanbank E	QLD	355	385	1/1/2000	12/31/2099	0.9977	0.04	0	24	28.39	48.39
Tarong 1	QLD	350	350	1/1/2000	12/31/2099	0.9673	0.05	19	37	12.83	32.83
Tarong 2	QLD	350	350	1/1/2000	12/31/2099	0.9673	0.05	19	37	12.83	32.83
Tarong 3	QLD	350	350	1/1/2000	12/31/2099	0.9673	0.05	19	37	12.83	32.83
Tarong 4	QLD	350	350	1/1/2000	12/31/2099	0.9673	0.05	19	37	12.83	32.83
Tarong North	QLD	450	450	1/1/2000	12/31/2099	0.9682	0.05	19	37	11.56	31.56
Torrens A 1	SA_W	122	126	1/1/2000	12/31/2099	0.9994	0.0444	0	24	46.65	66.65
Torrens A 2	SA_W	122	126	1/1/2000	12/31/2099	0.9994	0.0444	0	24	46.65	66.65
Torrens A 3	SA_W	122	126	1/1/2000	12/31/2099	0.9994	0.0444	0	24	46.65	66.65
Torrens A 4	SA_W	122	126	1/1/2000	12/31/2099	0.9994	0.0444	0	24	46.65	66.65
Torrens B 1	SA_W	200	206	1/1/2000	12/31/2099	0.9994	0.0444	0	24	43.17	63.17
Torrens B 2	SA_W	200	206	1/1/2000	12/31/2099	0.9994	0.0444	0	24	43.17	63.17
Torrens B 3	SA_W	200	206	1/1/2000	12/31/2099	0.9994	0.0444	0	24	43.17	63.17
Torrens B 4	SA_W	200	206	1/1/2000	12/31/2099	0.9994	0.0444	0	24	43.17	63.17
Townsv2	QLD	223	223	3/1/2005	12/31/2099	1.1452	0.0446	0	34	267.62	287.62
Townsv1	QLD	160	160	1/1/2000	3/1/2005	1.1452	0.0446	0	34	267.62	287.62
Tumut 1-01	SNOWY	82.4	82.4	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Tumut 1-02	SNOWY	82.4	82.4	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Tumut 1-03	SNOWY	82.4	82.4	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Tumut 1-04	SNOWY	82.4	82.4	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Tumut 2-01	SNOWY	71.6	71.6	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Tumut 2-02	SNOWY	71.6	71.6	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Tumut 2-03	SNOWY	71.6	71.6	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Tumut 2-04	SNOWY	71.6	71.6	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Tumut 3-01	SNOWY	250	250	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Tumut 3-02	SNOWY	250	250	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Tumut 3-03	SNOWY	250	250	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Tumut 3-04	SNOWY	250	250	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Tumut 3-05	SNOWY	250	250	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Tumut 3-06	SNOWY	250	250	1/1/2000	12/31/2099	NA	0	0	0	NA	NA
Vales Point 5	NSW_N	660	660	1/1/2000	12/31/2099	0.9901	0.0261	17	37	14.52	34.52
Vales Point 6	NSW_N	600	600	1/1/2000	12/31/2099	0.9901	0.0261	17	37	14.52	34.52
ValleyP	VIC_S	280	336	1/1/2000	12/31/2099	0.9636	0.0115	0	24	50.82	70.82
Wallerawang 7	NSW_N	500	500	1/1/2000	12/31/2099	0.9689	0.0261	17	37	13.49	33.49
Wallerawang 8	NSW_N	500	500	1/1/2000	12/31/2099	0.9689	0.0261	17	37	13.49	33.49
Wivenhoe 1	QLD	250	250	1/1/2000	12/31/2099	NA	0.0012	0	24	NA	NA
Wivenhoe 2	QLD	250	250	1/1/2000	12/31/2099	NA	0.0012	0	24	NA	NA
Yallorn W 1	VIC_S	350	360	1/1/2000	12/31/2099	0.9406	0.0186	10	24	2.21	22.21
Yallorn W 2	VIC_S	350	360	1/1/2000	12/31/2099	0.9368	0.0186	10	24	2.21	22.21
Yallorn W 3	VIC_S	360	375	1/1/2000	12/31/2099	0.9368	0.0186	10	24	2.21	22.21
Yallorn W 4	VIC_S	360	375	1/1/2000	12/31/2099	0.9368	0.0186	10	24	2.21	22.21

Appendix 3: Summary of Load Forecasts

Medium Economic Growth														
Summer Peak Demand					Winter Peak Demand					Annual Energy				
Year	NSW	QLD	VIC	SA	Year	NSW	QLD	VIC	SA	Year	NSW	QLD	VIC	SA
2003/04	12250	7663	8758	3017	2004	13040	7059	7801	2451	2003/04	71190	45225	44626	12899
2004/05	12720	8132	9045	3093	2005	13400	7383	7963	2515	2004/05	73340	46940	45300	12887
2005/06	13150	8540	9286	3158	2006	13660	7622	8054	2562	2005/06	75030	48402	46089	12840
2006/07	13560	8777	9472	3239	2007	13920	7802	8170	2630	2006/07	76790	49599	46560	12862
2007/08	13950	9058	9676	3314	2008	14230	8040	8355	2696	2007/08	78550	51440	47315	13102
2008/09	14370	9300	9952	3401	2009	14530	8227	8535	2762	2008/09	80360	52899	48233	13323
2009/10	14780	9564	10214	3486	2010	14820	8431	8745	2836	2009/10	82060	54457	49267	13511
2010/11	15160	9802	10488	3578	2011	15160	8617	8920	2915	2010/11	83850	56058	50521	13843
2011/12	15580	10041	10716	3674	2012	15450	8794	9113	2982	2011/12	85880	57792	51591	14231
2012/13	16040	10412	10954	3763	2013	15750	8975	9310	3060	2012/13	87520	59318	52464	14535
2013/14	16514	10797	11198	3854	2014	16056	9159	9512	3140	2013/14	89191	60885	53352	14845
2014/15	17001	11196	11448	3948	2015	16368	9347	9717	3222	2014/15	90895	62494	54255	15163
2015/16	17503	11609	11703	4043	2016	16685	9539	9928	3306	2015/16	92630	64145	55174	15487
2016/17	18020	12038	11964	4141	2017	17009	9735	10142	3393	2016/17	94399	65839	56108	15817
2017/18	18552	12483	12231	4241	2018	17340	9935	10362	3482	2017/18	96202	67579	57057	16155
2018/19	19100	12944	12503	4344	2019	17676	10139	10586	3573	2018/19	98039	69364	58023	16500
2019/20	19664	13423	12782	4449	2020	18020	10347	10815	3666	2019/20	99911	71196	59006	16853

Low Economic Growth														
Summer Peak Demand					Winter Peak Demand					Annual Energy				
Year	NSW	QLD	VIC	SA	Year	NSW	QLD	VIC	SA	Year	NSW	QLD	VIC	SA
2003/04	12250	7487	8687	3002	2004	13000	6893	7704	2399	2003/04	70960	44620	43872	12745
2004/05	12710	7724	8919	3052	2005	13320	7006	7797	2428	2004/05	72930	44548	44263	12577
2005/06	13110	7862	9055	3109	2006	13510	7000	7872	2459	2005/06	74330	43690	44628	12482
2006/07	13470	7934	9211	3171	2007	13670	7026	7921	2496	2006/07	75500	44205	45016	12549
2007/08	13810	8085	9324	3238	2008	13890	7138	8067	2539	2007/08	76740	45502	45341	12720
2008/09	14150	8155	9540	3304	2009	14090	7164	8203	2580	2008/09	77920	46442	46014	12870
2009/10	14470	8240	9742	3372	2010	14270	7199	8334	2617	2009/10	78990	47483	46779	13010
2010/11	14760	8292	9932	3438	2011	14490	7207	8414	2658	2010/11	80090	48213	47560	13239
2011/12	15090	8386	10057	3506	2012	14690	7248	8527	2695	2011/12	81520	49256	48105	13470
2012/13	15450	8539	10213	3572	2013	14880	7289	8642	2729	2012/13	82580	49178	48527	13661
2013/14	15819	8695	10371	3639	2014	15072	7331	8758	2763	2013/14	83654	49100	48953	13855
2014/15	16196	8853	10532	3708	2015	15267	7372	8875	2798	2014/15	84742	49022	49382	14051
2015/16	16582	9015	10696	3778	2016	15465	7414	8994	2834	2015/16	85843	48945	49815	14250
2016/17	16978	9179	10862	3849	2017	15665	7457	9115	2869	2016/17	86960	48867	50252	14452
2017/18	17383	9347	11030	3921	2018	15868	7499	9238	2906	2017/18	88090	48790	50693	14657
2018/19	17798	9517	11201	3995	2019	16073	7542	9362	2942	2018/19	89236	48713	51138	14865
2019/20	18222	9691	11375	4070	2020	16281	7585	9487	2979	2019/20	90396	48635	51586	15076

High Economic Growth														
Summer Peak Demand					Winter Peak Demand					Annual Energy				
Year	NSW	QLD	VIC	SA	Year	NSW	QLD	VIC	SA	Year	NSW	QLD	VIC	SA
2003/04	12270	7914	8819	3028	2004	13130	7296	7901	2523	2003/04	71410	45987	45040	13081
2004/05	12760	8593	9162	3122	2005	13580	7813	8088	2615	2004/05	74070	48613	45927	13194
2005/06	13220	9235	9446	3205	2006	13940	8265	8237	2702	2005/06	76340	51090	46811	13165
2006/07	13710	9739	9708	3301	2007	14320	8691	8410	2803	2006/07	78740	53478	47616	13265
2007/08	14200	10294	9983	3393	2008	14730	9190	8652	2902	2007/08	81260	56446	48660	13517
2008/09	14720	10780	10334	3496	2009	15150	9613	8912	3010	2008/09	83600	59427	49917	13730
2009/10	15240	11355	10687	3604	2010	15550	10108	9205	3122	2009/10	86050	62983	51437	13949
2010/11	15710	11878	11060	3708	2011	16020	10567	9457	3256	2010/11	88500	65909	53193	14309
2011/12	16220	12523	11367	3840	2012	16480	11121	9760	3370	2011/12	91450	69672	54728	14884
2012/13	16790	13067	11742	3958	2013	16940	11704	10073	3505	2012/13	94170	71722	56275	15314
2013/14	17380	13635	12129	4080	2014	17413	12318	10395	3645	2013/14	96971	73832	57866	15756
2014/15	17991	14227	12530	4205	2015	17899	12963	10729	3791	2014/15	99855	76005	59501	16212
2015/16	18623	14845	12943	4334	2016	18398	13643	11072	3943	2015/16	102825	78241	61183	16680
2016/17	19277	15490	13370	4467	2017	18912	14358	11427	4101	2016/17	105883	80543	62913	17162
2017/18	19955	16163	13811	4605	2018	19440	15111	11793	4266	2017/18	109033	82913	64691	17658
2018/19	20656	16865	14267	4746	2019	19983	15903	12171	4436	2018/19	112276	85353	66520	18168
2019/20	21382	17597	14737	4892	2020	20540	16737	12561	4614	2019/20	115615	87864	68400	18693

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