Report to

Office of the Renewable Energy Regulator

Modelling the Price of Renewable Energy Certificates Under the Mandatory Renewable Energy Target

29 October 2002

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Ref: J952 Report

Table of Contents

EXECUTIVE SUMMARY

The Mandatory Renewable Energy Target (MRET) Scheme is designed to encourage additional renewable energy generation and to reduce greenhouse gas emissions. So far, at least 1,500 GWh of additional renewable generation has occurred, compared with a cumulative target of 1,400 GWh for the first two years of the Scheme.

As the Scheme has been in operation for about 18 months, the Office of the Renewable Energy Regulator decided to undertake a study to review developments in the renewable energy market and their potential impacts on future prices of renewable energy certificates. The objectives of the study are to:

- Review operation of the market for renewable energy certificates.
- Identify key factors affecting market prices.
- Update projections of renewable certificate prices.
- Project the likely composition of renewable generation.

Performance of the Scheme

Trading of RECs commenced at around $25/MWh early in the first year increasing to approximately $36/MWh by the end of the year. RECs volumes bid for 2002 have also been low, but are still around the $36/MWh level. Looking forward, RECs are currently trading in a band between $34 and $37 going out three to five years with $38 available for 10 years with certain conditions. A floor in the forward REC price seems to emerge around $28 - $30.

Emerging commodity markets generally follow in a similar evolution and the REC market is no different. Initially an absence of information combined with a small number of players, resulted in relatively large swings in both spot and forward price. Price drivers in the early stages are based around perceived supply and demand issues and in the case of RECs are currently supported by retailer direct purchases from small solar hot water systems and capped by the shortfall charge.

Based on discussions with market participants, there are number of short term factors underpinning the RECs market:

- First, some exercise of market power has been occurring. Some of the larger suppliers appear to be supporting prices at the $35/MWh and $36/MWh level.
- Second, traders are also reluctant to enter into trades too early in a year because the final position of the large pre-1997 hydro-electric generators is not known for certain until towards the end of the year. The key issue facing the market at the moment is the level of 1997 base line for the hydro generators, which if too low will bury the REC market in its present form by flooding the market with surplus stock. However, this is likely to be an important phenomenon in the short term only.

- Third, trades have also been affected by some initial delays in granting accreditation and creation of renewable certificates.
- Finally, regulatory uncertainty has also impacted on the market. Many prospective generators are holding back their plans for new generation until after the review into the Act has been completed in 2003. This is likely to depress supply in the short term. Further, State based programs are fighting for a share of the action with draft legislation in the pipeline for carbon abatement products in direct competition with MRET.

The additional renewable generation created by the scheme has come from a number of sources. Based on data on RECs created, about 26% has come from hydro-electric generation, 33% from solar hot water heaters and solar generation, 14% from wind generation and 27% from biomass or waste to energy sources.

Furthermore, new renewable energy power stations have been encouraged as a result of the scheme. About 165 MW of new projects have been committed, comprising about 60% of new wind generation, 12% new mini-hydro schemes and the remainder biomass or waste based projects. Most of these projects will be commissioned over the next year.

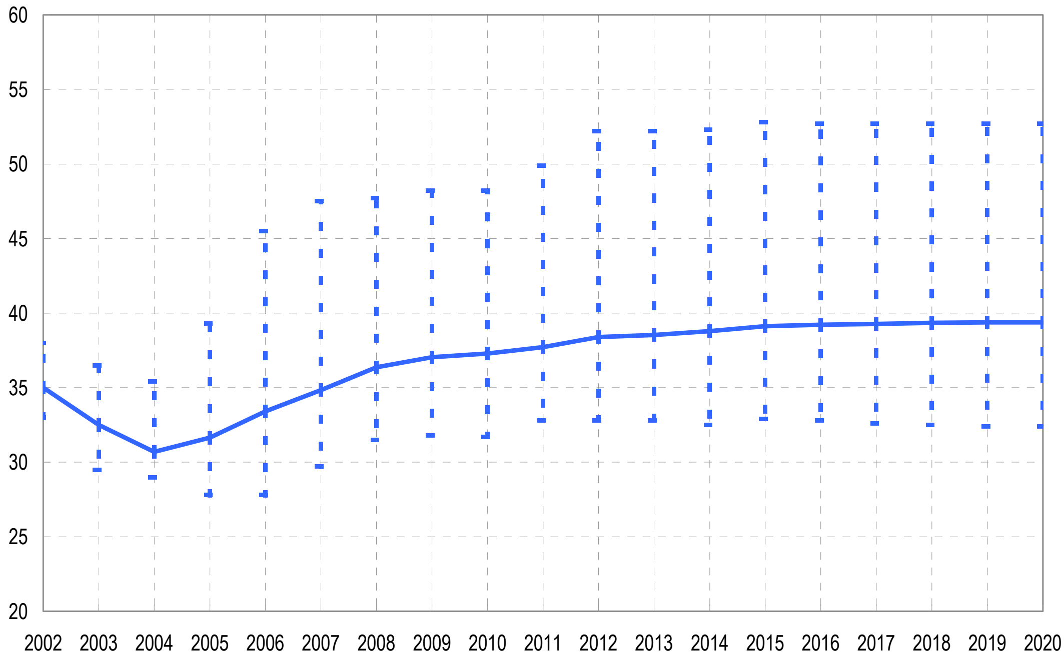
Outlook for REC prices

The price of renewable certificates is primarily a function of the cost of supply of renewable generation, the actual level of the generation required to meet the target and the structure of the wholesale market and the market for certificates. Because of banking, current prices in the RECs market will be based on the expectations of future market conditions of all traders involved. Thus, the current price will be an expected price based on a number of possible future market scenarios and the probability of these scenarios eventuating. Other short term factors may also impact on the price.

We have attempted to project certificate prices for a most likely outcome in terms of electricity price, availability of renewable resources and generation costs. We projected prices for a number of plausible alternative scenarios. We then calculated expected prices by taking into the probability of the scenarios eventuating. With this method, we estimate a band of plausible certificate prices as shown in Figure 1.

The certificate price is projected to decrease to $33 in 2003 and to then rise steadily to $37 in 2010. The price drops initially as there is an abundance of new renewable generation projected to enter the market. These plants enter the market early to maximise their production of REC's and hence benefit over the period. The price rises over the period as more expensive renewable energy is required to meet the targeted installed generation. If prices did not rise, more expensive forms of renewable energy would not be able to come into the market and the target would not be able to be met.

Figure 1: Expected and likely range of REC prices, $/MWh, real 2002 dollar terms



The forecast prices are lower than the forward prices currently available in the market by some $1 to $2 (about 3% to 5% lower). This may be due to different expectation about future events in the market and the impact of other key uncertainties not modelled in this study.

The outlook for certificate prices remains uncertain, with many factors that could lead to higher or lower prices than forecast. The key uncertainties include:

- Developments in the wholesale electricity prices, which impact on the revenue streams of renewable generators and hence the additional revenue required from RECs to justify entry into the market.
- Uncertainties in the cost of renewable generation, particularly fuel cost for biomass projects
- Supply uncertainty through the potential limit on the availability of renewable energy resources due to economic, environmental or technical circumstances.
- Potential for changes to the regulations particularly the level of the targets, shortfall charge and baseline calculations.

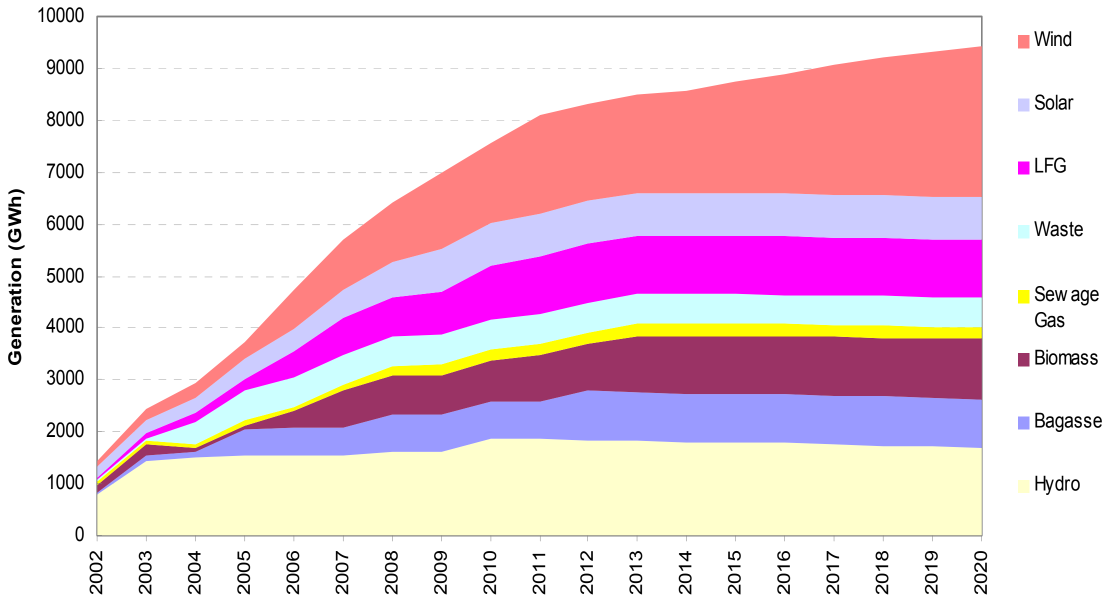
Based on a number of scenarios modelling these uncertainties, the price of RECs could range from $28 to as high as $52. The wide range reflects the immaturity of the market and the potential impact of the uncertainties listed above, particularly changes to the regulations.

Mix of renewable generation

Projection of generation by fuel type is shown in Figure 2. Existing plants dominate the market in the first two years of operation. By 2010, about 15% of the annual renewable generation comprises generation above baselines for pre-1997 generators. A further 10%

comprises renewable generation from upgrades of the large hydro-electric units and generation from plant commissioned between 1997 and 2001. Biomass and waste based generation projects comprise about 50% of the yearly generation. Wind is able to take up most of the rest due to its current under-utilisation is most regions.

Figure 2: Renewable Energy Mix for Base Scenario



Other issues

Apart from the uncertainties over the fundamental drivers in the market, a number of other issues have dominated. Two issues addressed in this study are the impact of above baseline generation from generators operating prior to 1997 and the interaction between the REC market and other green energy markets.

Generation above baselines

Analysis undertaken by the Australian Ecogeneration Association suggests that additional generation from existing plant are sufficient to reach the MRET target until 2008. This suggests that the MRET Scheme would fail in encouraging new investment in renewable generation.

The main contention is the impact of generation above baselines for renewable generators commissioned prior to 1997. A secondary issue is that the MRET scheme allows existing large hydro generators to accredit above average generation but are not penalised for generation below the baselines. This means that the average level of generation available to be created for RECs from per 1997 plant is higher.

Our analysis indicates the MRET is likely to encourage new generation as early as 2004, despite the issues raised by the AEA. Our analysis indicates that banking provides a significant incentive for generators to enter the market earlier than required to meet the target.

The level of banking is such that new generation could enter the market from 2004. If no banking was assumed, then our analysis would indicate that new generation would not be required until 2006. Of course part of this new generation could come from upgrades of existing hydro-electric assets, but there is sufficient demand for banked certificates for other new renewable generation to be required early on.

Our analysis indicates that existing renewable generators will have an important influence on the market over the next two to three years. Their trading strategies will have a significant influence on certificate prices in this period. But their influence on the market is likely to wane from 2004 onwards as new renewable generators enter the market.

Impact of Green Power

Green Power is a product retailed to consumers comprising electricity sourced from accredited renewable generation. Green Power is usually sold at a premium, but to earn this premium they cannot generate RECs from the same generation sold as Greenpower. This creates an incentive for retailers to differentiate sales of electricity, allowing them to potentially earn higher returns on Green Power sales and to enable them to develop a brand identity.

Diversion of renewable generation to Green Power schemes results in higher prices for renewable energy certificates. This occurs because more and higher cost renewable options will be required to meet the MRET target. However, sales of Green Power are projected to remain low, at around 1% of total sales. Because of the small amount of Green Power sales, the impacts on certificate prices will be small with certificate prices being at most 5% higher than they would otherwise be.

1 INTRODUCTION

The Commonwealth Government has introduced legislation to mandate the supply of an additional 9,500GWh of renewable energy by 2010 as part of Australia's commitment to reducing our greenhouse gas emissions and to develop a renewable energy industry. The Mandatory Renewable Energy Target Scheme (MRET) has been set up as an obligation on electricity retailers and large consumers to purchase an increasing percentage of their power requirements from renewable sources. To facilitate this objective, qualifying renewable energy generators are permitted to create tradable Renewable Energy Certificates (RECs) for each MWh of renewable electricity generated.

As specified in the Renewable Energy (Electricity) Act 2000, the main aims of the scheme are:

- To encourage the additional generation of electricity from renewable sources.
- To reduce emissions of greenhouse gases.
- To ensure that renewable energy resources are ecologically sustainable.

The tradeable RECs are a component of the scheme that enables the renewable energy targets to be met at least cost.

The market for RECs has been in existence since April 2001. The Office of the Renewable Energy Regulator contracted McLennan Magasanik Associates to review developments in the market and their potential impacts on future market prices.

The objectives of the study are to:

- Review operation of the market for renewable energy certificates.
- Identify key factors affecting market prices.
- Update projections of renewable certificate prices.
- Project the likely composition of renewable generation.

2 MARKET FOR RENEWABLE ENERGY CERTIFICATES

2.1 The Renewable Energy Certificate Scheme

2.1.1 General Operation of the Scheme

The scheme operates through an obligation on "liable parties" (essentially those parties who purchase electricity through the wholesale market, basically electricity retailers and large customers) to submit a legislated number of RECs in proportion to their electricity purchases in each year of the operation of the scheme.

The Act specifies that the renewable energy target scheme applies to electricity sales in all grids above a specified threshold of 100 MW. Based on this threshold, grids included are:

- The National Electricity Market (NEM), covering the interconnected grids of Queensland, New South Wales, Victoria and South Australia. Although not yet interconnected, the Tasmanian grid is also part of the NEM and included in the renewable energy target scheme.
- The South West Interconnected System of Western Australia.
- The North West Interconnected System.
- The Darwin - Katherine grid.
- The Mt Isa Region grid.

Although customers supplied by smaller grids are not liable under the scheme to source electricity from renewable generation options, renewable energy in those systems can still contribute towards meeting the target in other grids.

2.1.2 Renewable Energy Targets

Targets for the level of renewable generation in each year have been set in the legislation. These interim targets are designed to discourage liable parties from delaying investment to just prior to 2010, with the risk that such delays would make it difficult to meet the target.

The interim targets are included in the Act, and stipulate a final target of 9,500 GWh of renewable generation in 2010 extending to 2020. The interim targets for the market as a whole are presented in Table 2.1.

Table 2.1: Interim Targets (GWh/year)

Year	Target

2001 (April to December)	300
2002	1,100
2003	1,800
2004	2,600
2005	3,400
2006	4,500
2007	5,600
2008	6,800
2009	8,100
2010 & later years	9,500

2.1.3 Creation of certificates

Accredited generators are allowed to create RECs (in electronic form) for renewable electricity supplied to an agreed measurement point. Certificates created must be registered with the ORER. The REC registry is maintained by M-Co (at www.rec-registry.com). Each certificate represents 1 MWh of renewable electricity generated. Fractions of a certificate will not be issued. A generator producing between 0.5 and 1 MWh/year would create one certificate with its generation rounded up to nearest MWh. To maintain confidence in the system, provision is made in the legislation for the auditing of the creation of RECs by accredited renewable generators.

Liable parties under this mechanism will be required to acquire and surrender renewable certificates equivalent to the target proportion of their sales or consumption in each accounting period. In any period, liable parties can purchase more certificates than required to achieve their target, with the surplus traded to other liable or third parties or banked to be surrendered in a future accounting period.

Generators will have the option of trading their certificates to a liable party or through a third party, and will achieve the price premium that supports the development of the project, through the sale of certificates. The price that is likely to be obtained for the certificates will influence greatly any decision to invest in renewable energy generation.

2.1.4 Penalty for non-compliance

Liable parties who fail to submit the required number of certificates in each accounting period will be required to pay a penalty for the shortfall of $40/MWh. This penalty is not indexed to CPI. The penalty is also not tax deductible, meaning that under current company tax rates a liable party would be indifferent between paying the penalty or purchasing certificates up to a price of $57/MWh. A 10% leeway is available to retailers who fail to comply fully with the requirements. Shortfalls of more than 10% will be penalised for the full quantum of the shortfall, although this penalty may be redeemed by surrendering additional RECs in the following three years. Shortfalls within the 10% leeway can also be made up in the following years.

2.2 Interaction between RECs and Greenpower Schemes

Greenpower schemes are operated voluntarily by electricity retailers to market electricity generated from accredited renewable sources. Critical to the operation of these schemes is the verification and auditing of retailers of green electricity purchases to ensure that enough renewable electricity is purchased to cover the retailers' Greenpower sales.

The introduction of the REC scheme has complicated the Greenpower scheme and there was considerable uncertainty as to whether generation could be accredited for both and therefore gain two additional revenue streams. This confusion was resolved through new Greenpower accreditation rules that essentially mean that renewable generation may be either used for the RECs or sold as Greenpower, but not both.

Purchases for Greenpower have largely been under long term supply agreements between the retailer and the generator, with electricity output and green component of the electricity being purchased under a single agreement. The introduction of the REC scheme has enabled the separation of the renewable component and the electricity itself allowing them to be sold separately. This means that sales of RECs can be completely separate from electricity sales and managing the sale into two distinct markets becomes an important component of managing a renewable electricity generator.

While the options for the sale of Greenpower are generally limited to two party long term supply contracts, the sale of RECs may be through the spot market, under a hedging contract or through a long term contract. However, for many generators a long term contract for REC sales as well as electricity sales will be required to support the financing decision for the construction of the plant.

The decision a generator must make therefore is whether there is more value in the RECs or from Greenpower sales.

2.3 Developments in the REC Trading Market

RECs have been traded in the energy market since April 2001 as retailers have been endeavouring to purchase RECs to meet their renewable energy targets in compliance with their regulatory obligations to the scheme.

In order for the renewable energy generators and the liable parties to manage their risk of meeting their obligations under the scheme they need to consider all the market trading opportunities to optimise their positions. Options to be considered include:

- Should the renewable energy generators sell all their RECs in the early period of the market?
- If they sell them to the liable parties would the liable parties profit from the purchase by arbitraging?

- Will the liable parties be able to purchase RECs on the market at any point of time or should they purchase them early and bank them for later years and possibly trade them.
- A valuation of the price of RECs is critical to the decision making process by the renewable energy generators and liable parties.
- The uncertainty faced by some of the generators, for example large Hydro generators, in determining the availability of their RECs until the fourth quarter of the year.

These decisions have to be made in the best interest of each of the parties to optimise their benefits from RECs trading market. A reliable price forecast for the RECs market will help these parties to meet their obligations and maximise their benefits.

One of the main factors in determining the price of RECs is the level supplied in the market by generators or the liquidity of the financial market in supplying the financial instruments to trade RECs. The framework for trading RECs is already established for the parties to participate in trading RECs. To date, trading of RECs has been modest due to:

- Small percentage of RECs required for the first and second years of the operation of the scheme.
- Market participants focusing more on their long-term strategies for their entire businesses and little effort on developing strategies for sourcing and trading RECs.
- The lack of liquidity in the financial market to trade RECs.

Trading of RECs commenced at around $25/MWh early in the first year increasing to approximately $36/MWh by the end of the year. RECs bid for 2002 have also been low, but are still around the $36/MWh level. There are further out bids to calendar 2006 at levels in the low $30s.

Based on discussions with market participants, there are number of short term factors underpinning the RECs market. Because of the relatively small number of suppliers of RECs, some exercise of market power has been occurring. Some of the larger suppliers appear to be supporting prices at the $35/MWh and $36/MWh level. Traders are also reluctant to enter into trades too early in a year because the final position of the large pre-1997 hydro-electric generators is not known for certain until towards the end of the year.

Trades have also been affected by the long time taken to grant accreditation and to create renewable certificates.

Finally, regulatory uncertainty has also impacted on the market. Many prospective generators are holding back their plans for new generation until after the review into the Act has been completed in 2003. This is likely to depress supply in the short term.

All these factors are likely to be less of an influence in the long term as the size of the market expands and as trading becomes more liquid. Prices should stabilise according to fundamental supply and demand drivers. But there will still be some variation in prices within the year due to the intermittent nature of much renewable generation.

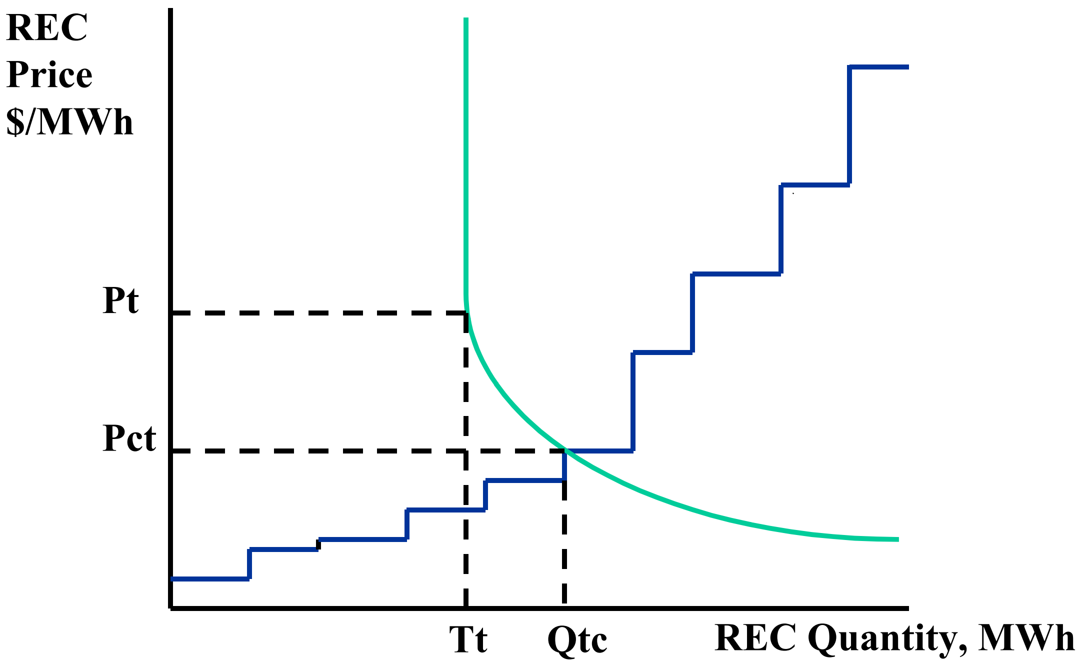
3 METHOD AND ASSUMPTIONS

3.1 Price formation

The price of renewable certificates is primarily a function of the cost of supply of renewable generation, the actual level of the generation required to meet the target and the structure of the wholesale market and the market for certificates. However, there may also be some other factors affecting prices for a short duration, driving prices away from the levels that would prevail if they were just based on the fundamentals. The factors affecting prices are described below.

Assuming a competitive market and low transaction costs, price formation in the certificates market can be represented by Figure 3.1. The horizontal axis represents the quantity of certificates required in MWh. The vertical axis represents the price of certificates in $/MWh. The quantity, *Qt*, represents the renewable target in year *t*. The step curve designated *Ct* represents the net cost of renewable energy technologies. The net cost is equal to the total cost of the technology levelised over their project life and subtracting revenues received other than from certificates. This revenue may include receipts from transactions in the wholesale electricity market, avoided network costs brought about by embedded renewable generation and revenue from other outputs of renewable generation[1]. Each step represents the cost of a particular renewable energy source, where the renewable energy source is defined by type of technology and its physical location. The price of the certificates, *PCt*, is equal to the net cost of the last technology required to meet the specified target in year *t*.

Figure 3.1: Price formation for renewable energy certificates



1 For example, the avoided cost of waste disposal that would be incurred if wood waste is not used as a fuel source.

Under a competitive market regime with fully informed participants, the market clearing price for certificates equates with the levelised cost of the last renewable energy source required to meet the target. A higher price would encourage other higher cost renewable options to enter the market. A lower price would not encourage sufficient renewable generation in the market.

There are a number of important characteristics of the process of price formation. First, the cost structure for many renewable technologies is characterised by high up-front capital cost but low operating costs. The total cost of many renewable technologies is also likely to be higher than the total cost of conventional alternatives over the short to medium term. With these factors, renewable energy generators are unlikely to enter the market unless supported by long-term contracts. This factor is recognized by the extension of the scheme to 2020, allowing for participants to enter into long-term contracts to enable the recouping of costs over that period[2].

The MRET scheme applies for a period of 20 years, from 2001 to 2020. This period defines a lifetime on the value of a certificate, so that the RECs become valueless after 2020. In developing a model for certificate trading, we assume renewable energy suppliers are risk averse, and would only be interested in entering the market under long term contracts covering all or a substantial part of their output. This carries additional risks for retailers who have to pass on the cost of these contracts to contestable customers. Such risks and their implications for price setting are discussed below.

Second, intra-marginal units receive revenue in excess of their levelised cost. This is a function of the cost curve, which assumes discrete steps in costs, as more renewable energy generation is required. If there is asymmetry of information, with retailers being more informed than individual renewable energy generators, and a lack of competition it is possible that renewable energy generators receive only their levelised cost, with retailers or third parties securing a large part of the surplus on any on-sale of certificates.

Third, it is expected that the cost of renewable energy generation will fall over time. Given that the certificate price is strongly dependent on the cost of renewable generation, it is to be expected that the certificate price would be likely to fall over the long term, all other factors equal. In opposition to this trend the resource availability of many renewable sources will reduce and tend to increase costs. For example, while current wind generation locations may have capacity factors in the range of 35% to 40% as the good sites are used the capacity factors at available sites will reduce, and contribute to higher generated costs. In the very long term a situation where renewable electricity was cost comparable with fossil generation would result in the certificate price approaching zero and the renewable certificate market becoming unnecessary. The likelihood of this occurring in the timeframe of this study is, however, extremely low.

2 The target in GWh specified for 2010 is continued until 2020.

The price of certificates is a function of:

- Regulations affecting supply of renewable energy.
- The demand for certificates, defined primarily by the interim targets and subject to regulatory change.
- The underlying cost of renewable energy technologies, including the cost of any network upgrade required to supply the grid.
- Prices received for renewable energy generation in wholesale electricity markets.
- Revenue earned from other potential services provided by renewable generation, such as the ancillary services, avoidance of network costs, and avoidance of waste disposal costs.

3.2 Method

3.2.1 Overview

Because of banking, current prices in the RECs market will be based on the expectations of future market conditions of all traders involved. Thus, the current price will be an expected price based on a number of possible future market scenarios and the probability of these scenarios eventuating. Other short term factors may also impact on the price. In our modelling, we attempt to project certificate prices for a most likely outcome in terms of electricity price, availability of renewable resources and generation costs. We also project prices for a number of plausible alternative scenarios. We then project expected prices by taking into account the probability of the scenarios eventuating. With this method, we estimate a band of plausible certificate prices.

The modelling is based on the premise that a renewable energy certificate will trade at a value that will enable the marginal generator to operate economically, while meeting the mandatory interim targets. The value of a certificate may be determined from the difference between the levelised cost of generation of the marginal renewable generation unit and the electricity price obtained in the market for the thermal generation it displaces.

Thus, the basis of the projections of the price of renewable energy certificates is that the certificate price will relate directly to the cost of renewable electricity generation. Specifically, the renewable certificate will equate to the difference between the cost of the lowest cost renewable energy required to meet the mandatory target and the price for the electricity that can be obtained in the wholesale market. The cost of the last renewable option dispatched to meet each of the interim targets sets the market clearing price and the certificate price.

This approach may result in higher certificate prices than actually eventuate as it is likely that low cost renewable energy will be locked into long term contracts relatively early to meet the purchasers own requirements. If this occurs a significant proportion of liable parties may be purchasing certificates at below the market-clearing price. Further, the assumption of a single market-clearing price also depends on a highly competitive market for certificates.

Certificates are valid for all periods up to 2020. Thus, in this analysis banking of certificates over periods is allowed to occur where economic. This allows generators to hold their certificates until a later date when a more attractive price may be available. Banking of certificates may also reduce the total cost of the scheme by delaying the introduction of more expensive generation. It also means that all targets could be met by a group of renewable generators creating less than 9,500 GWh for a period beyond 2010.

3.2.2 Forecasting Electricity Prices

Detailed discussion of the various price drivers and assumptions that affect the electricity market modelling are included in Appendix A. We also indicate how these are incorporated into our methodology, either influencing data inputs into the market simulation models, effecting changes within the model data or in the post-processing of results. In essence the forecast electricity pool prices is based on the marginal costs of the generating units in the National Electricity Market (NEM), transmission characteristics between the regions, bidding strategies of the generating companies and the forecast electricity demand.

3.2.3 Forecasting REC Prices

The estimation of REC prices is based on the assumption that the price of the REC will be the difference between the cost of the marginal renewable generator and the price of electricity achieved for that generation. The basic tenet behind the method is that the REC provides the difference, in addition to the electricity price, that is required to make the last required (marginal) renewable energy generator to meet the REC target viable.

In a simple system the REC price would be determined by identifying the marginal generator and performing a simple subtraction of these two values. However, the following complications arise:

- Introduction of new renewable generators impacts on the electricity price paths, resulting in the requirement for iteration of the market price forecast and the REC estimation.
- The allowance of banking in the REC market results in the requirement for an inter-temporal optimisation.
- Currently installed and committed generators are installed regardless of the estimated economics.
- Generation resulting from the upgrade of large hydro units is treated in our hydro dispatch model to account for the additional dispatch that could be achieved with refurbishment to achieve higher efficiency in generation.
- Resource and other constraints limit the uptake of renewable generation.

The optimisation requires that the interim targets are met in each year (by current generation and banked certificates) and generation covers the total number of certificates required.

The certificate price path is set by the net cost of the marginal generators, which enable the above conditions to be met and result in positive returns to the investments in each of the projects.

The MMA REC Model determines the future price path of REC's in the following steps:

- Determine wholesale electricity prices for each hour of the projection period in each State.
- Assign regional prices to renewable projects according to location.
- The pool prices are then time-weighted according to the operating cycle of the available renewable energy alternatives. For example, waste process generation would operate 24 hours per day and would therefore be represented by the average time-weighted pool price. Whereas, photovoltaics would only operate through daylight hours, achieving the prevailing market price for these hours only. Solar hot water systems although using solar energy during daylight hours, actually replace off-peak electricity usage so the surrogate price for this option is the off-peak price for the replaced energy.
- Subtract weighted price from corresponding renewable project levelised cost and then determine the merit order of the projects by ascending net costs (apart from those flagged as committed). The generation required to meet the interim targets in each year will then set the initial, non-banking, solution of the price path, and act as starting values for the solution with banking.
- The generation output from each project is calculated from the MW and capacity factor for each project.
- For each selected option the REC values over the next 15 years of generation are discounted with the electricity sales income, and revenues from any other programs (e.g. steam sales). The discounted cash flow compared with the levelised cost indicates the whether a given REC price path will justify the construction of a project.
- The REC path is optimised over the 20 years of the program subject to the constraints indicated above.
- The plant installed in each year is determined by the economic viability subject to the REC price path, and also subject to resource constraints, REC creation and surrender constraints. The resource constraints are indicated by capacity available from each source and region in each year.
- The resulting MW installed and generation levels are then required as inputs to the pool price model to determine the resultant pool price changes that in turn impact the REC prices.
- The process is repeated until stable pool price paths, REC paths and installed renewable generation options are achieved.

The method also accounts for dynamic factors in choosing new plant. Choice of new plant in each year is constrained by the following factors:

- Manufacturing capacity (solar hot water, PV modules, wind turbines).
- Development lead times, which effectively constrains the choice of new plant in the first three years of the analysis to projects that are already under construction or with development lead times of less than 3 years.
- Availability of fuel resources, in which the fuel cost of biomass projects is effectively increased over time to reflect the sourcing of fuel over a greater distance from the plant;
- Inclusion of only a few projects located near large metropolitan centres.

3.2.4 Greenpower Contribution

The projection of the future prices of the premium attached to Greenpower, on top of the electricity price, is particularly difficult. Electricity sold as Greenpower is normally subject to long term power purchase agreements (PPAs). These PPAs are off-market contractual arrangements that are normally confidential to the parties involved. This means that determining current prices for Greenpower purchases are extremely difficult let alone determining a basis on which to forecast prices for 15 to 20 years.

The major assumption that can be made is that the premium paid will be sufficient to enable the economic operation of the generator. The value of the premium, taken in isolation for the REC market, could be higher or lower than the value of a REC in any given year. However, if we assume that a generator is able to meet the criteria for both schemes, if the Greenpower premium was lower than the REC price, then the RECs would be sold in the REC market. On the other hand if the Greenpower premium was higher than the REC price then the electricity would be sold as Greenpower, subject to the level of demand for Greenpower.

As law mandates the REC requirements and Green Power is voluntary we assume that REC requirements will be met by retailers prior to Green Power requirements. It is economically rational therefore that Greenpower purchases would be sourced from the next least expensive options after the REC targets are met. This argument forms the basis of our analysis, however a number of significant complications arise:

- Generators not eligible for RECs (predominantly, pre 1997) may be used as Greenpower at prices less than the REC price.
- Informational asymmetry between purchaser and seller may result in premiums paid below the REC price.
- Generators may sell Greenpower for reasons other than purely economic ones.

The Greenpower price premium is therefore forecast on the basis of the price required to meet the REC targets plus the additional generation for Greenpower commitments. The additional requirement is equivalent to the current market size of Greenpower (just under 1% of total electricity demand). Only those renewable projects eligible for Greenpower are included in the analysis. Once the projects supplying Greenpower have been selected, then the REC price model is applied to the remaining projects.

3.3 Main Assumptions

All dollar values are real 2002 Australian dollars. Levelised costs of renewable generation have been calculated over a 15-year time period using a real pre-tax weighted average cost of capital of 8.3% as have revenues. This time period reflects the typical time period used for debt finance of generation projects.

Certificates are valid for the entire 20-year period and may be held, or banked, over this period for surrender in a later period.

3.3.1 Project data

The database for the model contains over 200 renewable energy generation projects. Each of these projects has a levelised cost of generation calculated from estimates of capital cost, operating and fuel costs, and the costs associated with connection to the transmission network. Where data has been available the costs include the costs of connection to the grid, which can form a significant proportion of the capital costs of a project, particularly where no local transmission wires are available.

Each project considered in the modelling exercise has a levelised cost of generation estimated for each year in which it could be installed. These project costs vary over time largely as a result of capital cost reductions in real terms over the study period. These reductions are expected as new technology generation reaches larger scales of manufacturing and improvements in construction and efficiency occur. The capital cost reductions over time are applied to current capital costs as a percent reduction in cost for each year of project delay. The largest reductions are applied to the newest technologies, particularly for wind and solar generation, which are expected to show rapid reductions in capital cost over the next 20 years.

3.3.2 Treatment of existing and committed renewable generators

Where a generation plant is already operating (but commenced after 1997), is under construction or committed for construction we have forced the plant into the model regardless of our estimates of generation cost. This committed generation forms the starting point for the renewable energy generation and results in sufficient generation already installed to meet the 2001 interim target.

Existing renewables are defined as that commissioned before 1997 at the time the measure was introduced. These renewables are not eligible for renewable energy certificates, except for the proportion above their calculated base lines. Any increase in the generation output of these projects is assumed to be eligible for the allocation of certificates. As an example, although the major hydro schemes would not be eligible for certificates on their total generation, any upgrades to equipment which produce an increase in generation, over long term average levels, would be eligible for certificates.

We have specifically modeled the increase in hydro generation that may be obtained from upgrading the turbines on existing hydro systems, based on the long-term average generation and the variability in annual energy input into the hydro schemes. Due to the low capital and operating costs of these upgrades we have assumed that these projects are scheduled throughout the ten-year target period to achieve a realistically achievable sequence of plant expansion. Tasmania's hydro-electric potential has also been modified to account for the higher energy as a result of Basslink (which alters the way hydro-electric generation occurs, resulting in slightly higher "head" and therefore higher energy conversion).

We have also specifically modeled the expected decline in generation from the existing large hydro schemes. In particular, generation at the Snowy Mountain Scheme was reduced by 450 GWh to reflect the impact of increasing discharges to the Snowy River by 15%. To reflect the impact of this reduction, the base line for the Snowy Mountain Scheme was reduced by the same amount.

3.3.3 Baselines

Baselines for generators commissioned before 1997 are based on typical generation that would have occurred for each generator in that year. Typical generation was determined using historical generation data for up to 10 years before 1997 where available. More recent data was used for projects which do not have an adequate historical data (e.g. some of the landfill gas and mini-hydro projects). For generating units owned by Hydro Tasmania, typical generation patterns were derived using an interpolation procedure using historical data.

Based on this approach, the available generation above baselines for generators commissioned prior to 1997 are shown in Table 3.1. Existing generators can generate more from improvements in management practices or upgrades of existing equipment.

Table 3.1: Generation potential of generators commissioned prior to 1997 to be used for meeting MRET, GWh per annum.

Generator	Amount of Eligible Generation, GWh
Hydro Tasmania	686
Southern Hydro	125
Snowy Hydro Electric Scheme	242
Stanwell Corporation	83
Other	128
Total	1,264

4 MARKET OUTLOOK

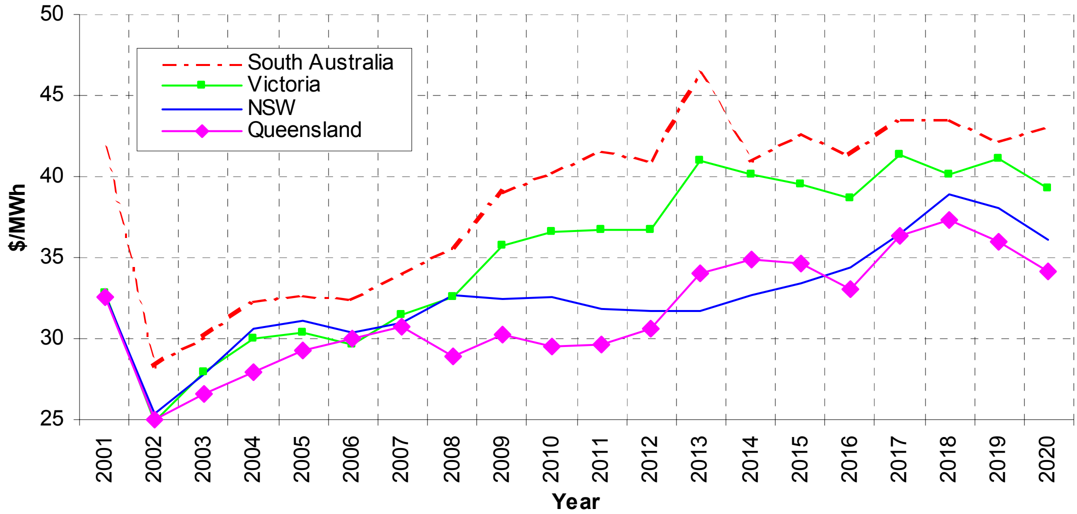
In this Section, we present the projections of renewable energy certificate prices based on the approach described above.

4.1 Wholesale electricity prices

The pool price forecasts developed using MMA's market simulation models of the National Electricity Markets (NEM) and the South West Interconnected System (SWIS) were based on annual average prices at each of the regional nodes. These prices have been discounted by the marginal loss factor at the appropriate location.

The annual average regional pool prices as forecast for the base scenario study are presented in Figure 4.1.

Figure 4.1: Forecast Regional Pool Prices ($/MWh), 2002 dollar terms



There are three phases in the price path:

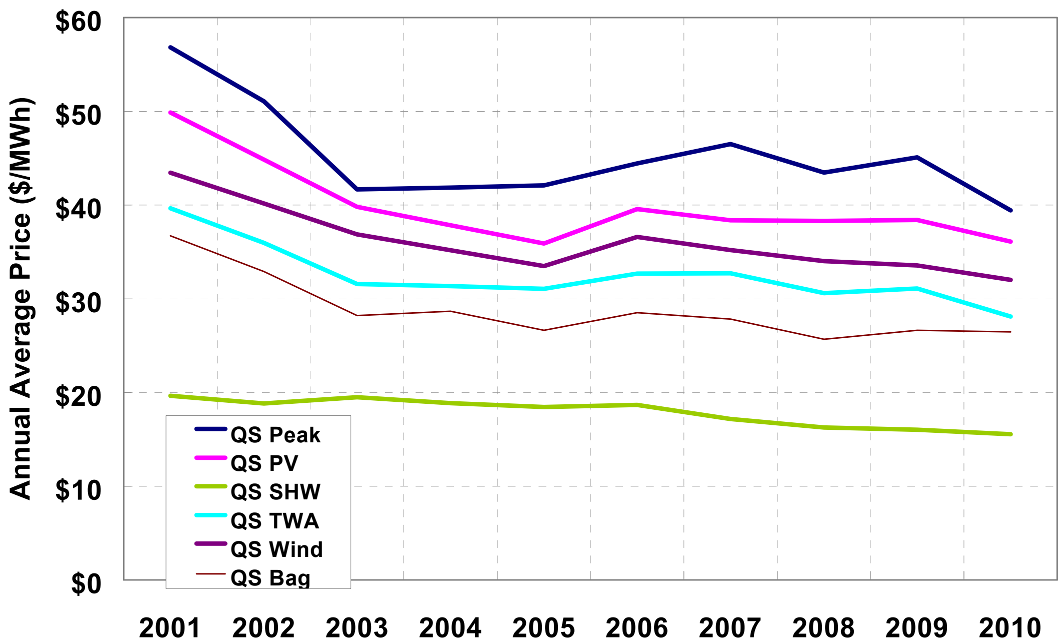
- The current prices dip in 2002 which was driven by an exceptionally mild summer following the extremely hot summer of 2001. This shows the possible sudden change in price levels that can occur when surplus capacity coincides with mild weather.
- A period to 2007/08 during which competition is expected to be strong and prices are expected to be about $3 - $5/MWh below new entry costs on average
- The period from 2008/09 when supply margins will again become critical and the extent of supply response will determine prices. The price path that is shown follows first year new entry prices.

Prices are not expected to rise significantly in the next few years because the demand growth will be taken up by the early contribution from renewable energy and the new conventional plants already committed.

In the longer term we would expect some price cycles above and below new entry costs as has been recently observed. These regional average prices do not necessarily reflect the price that a generator will receive for their generation in the market, because of the temporal variations in generation output that occur with some types of generation.

Renewable generation of some types in particular is subject to diurnal output profiles, over which the operator has little control such as wind or solar generation. Wind and solar generation will generally receive a higher electricity price than the time weighted average reported above because of the natural tendency to produce higher outputs during periods of peak demand. To account for these variations in output generation we have produced load weighted average prices for the typical generation profiles that these non-controllable generation types produce. The load weighted price forecasts for a number of typical generation types are presented in Figure 4.2 and show the higher than average prices that could be achieved by wind and solar generation. Interestingly the prices for solar hot water systems are very low because the electricity displaced is assumed to be off-peak and therefore the corresponding price for the demand reduction is that during the early hours of the morning rather than the higher prevailing prices during the sunlight hours.

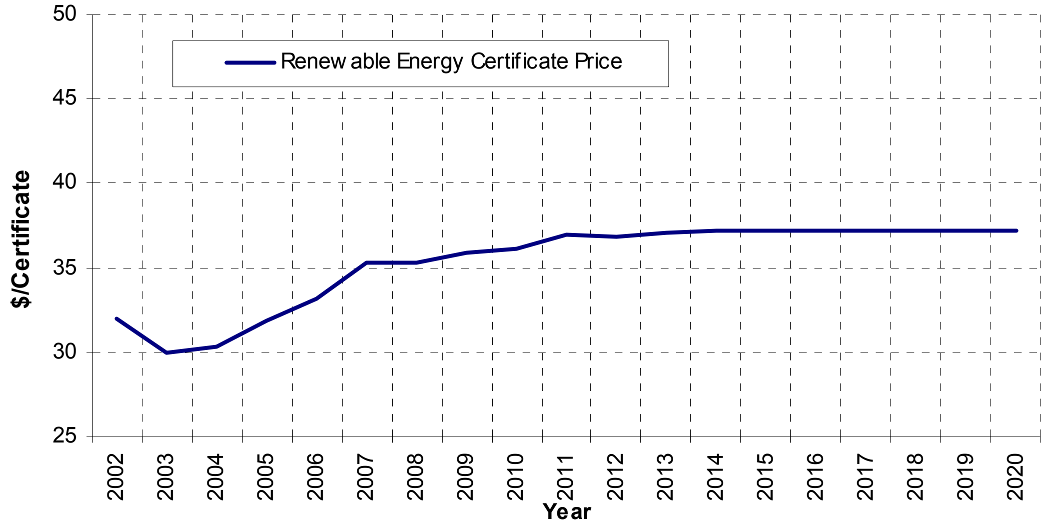
Figure 4.2: Load Weighted Pool Prices, Queensland, ($/MWh)



4.2 Certificate prices

The forecast Renewable Energy Certificate Price is presented in Figure 4.3. The price reduces to $30 in 2003 and then rises steadily to $37 in 2020. The price drops initially as there is an abundance of new renewable generation entering the market. These plants enter the market early to maximise their production of REC's and hence benefit over the period. The price rises over the period as more expensive renewable energy is required to meet the targeted installed generation. If prices did not rise, more expensive forms of renewable energy would not be able to come into the market and the target would not be able to be met.

Figure 4.3: Renewable Energy Certificate Price Projection for Base Scenario



The cumulative target of 138,700 GWh is exceeded by 1,394 GWh over the 20-year period. Cumulative generation never falls below the target. Both the cumulative generation and the banking for the Base Scenario are shown in Figure 4.4. The highest level of banking is 8.4 million certificates in 2008. The amount of certificates banked reduces towards 2020 as it assumes that their value will be worthless after this date.

Figure 4.4: Cumulative Generation and Banking for Base Scenario

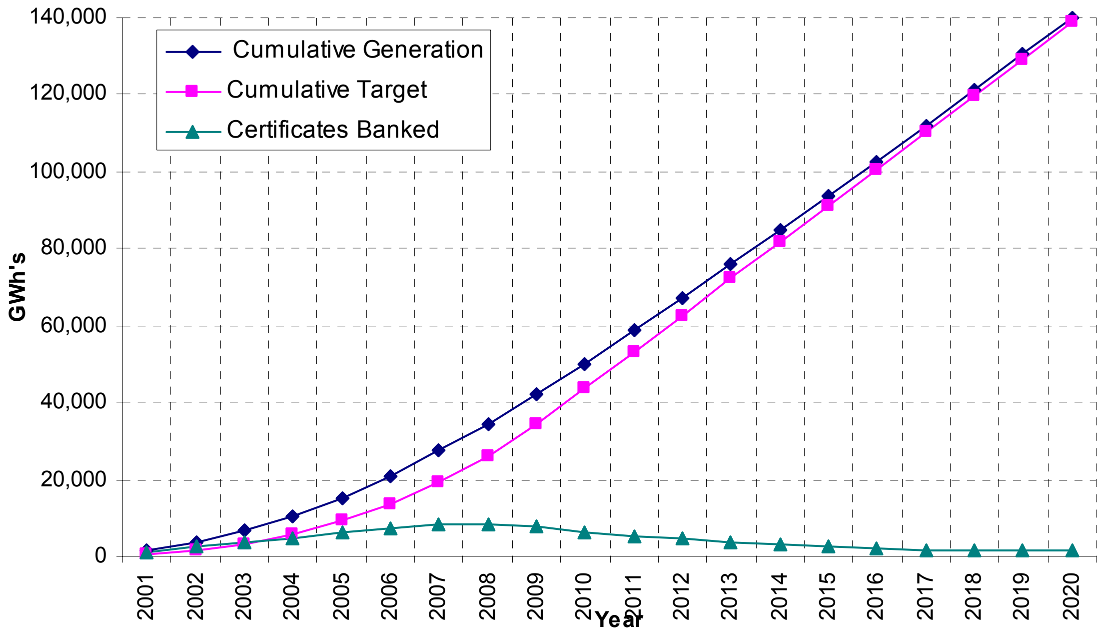
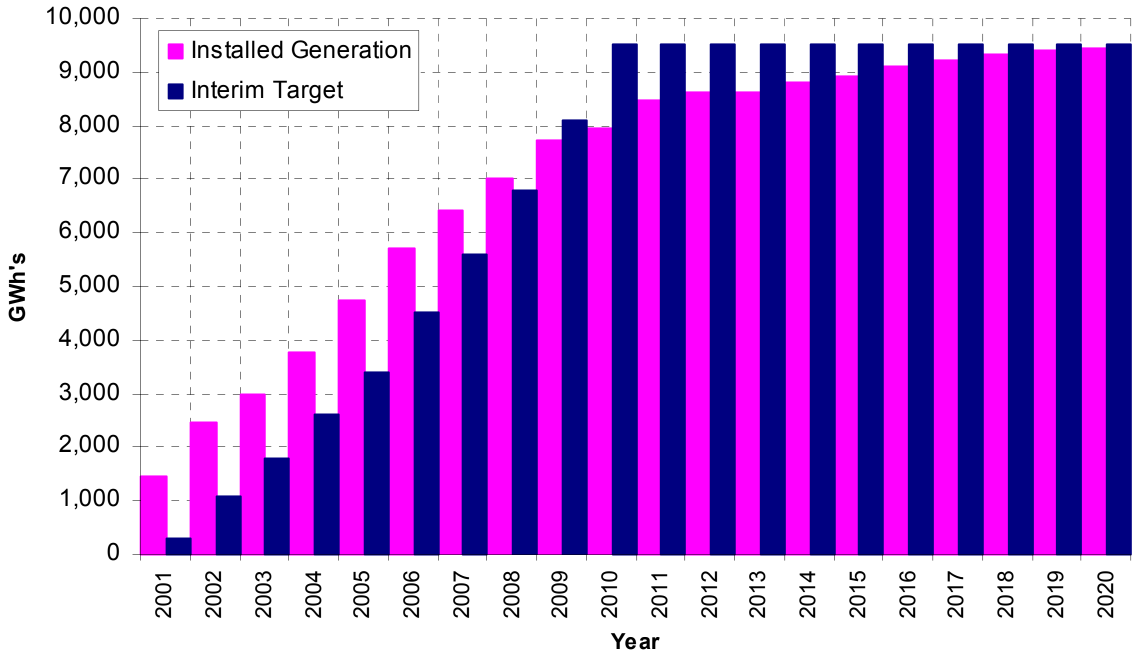


Figure 4.5 shows the projected level of renewable generation in the Base Scenario versus the MRET target in each year. When projected generation is above the target, the surplus is

banked for latter use. In years when the projected level of generation is below the target, the deficit is made up of banked certificates from surplus generation in prior years.

There is a lot of capital invested in early years, with the level of installed generation rising significantly above the target. Only in 2009 does the level of installed generation fall below the target. The installed generation target of 9,500 GWh's does not need to be met with the availability to banking to generators. Effectively by using certificates created, but not required in earlier years, capital costs for investing into new plant towards the end of the period to meet this target are not incurred. Banking enables the MRET scheme to use cheaper renewable energy to meet the target.

Figure 4.5: Projected Renewable Energy Generation for Base Scenario

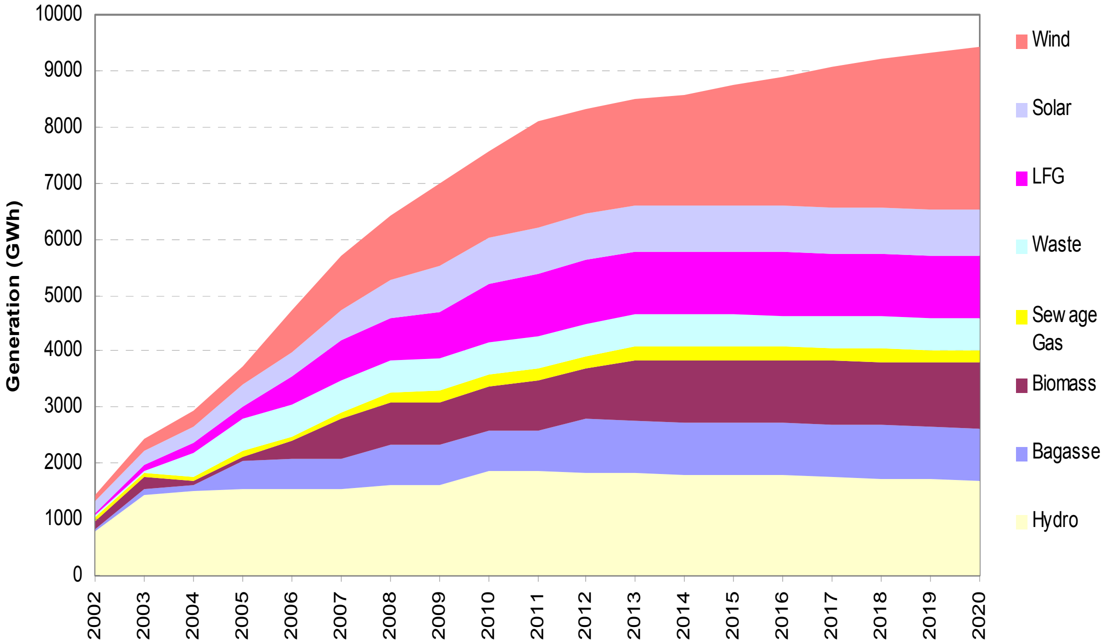


4.3 Renewable generation portfolio

Figure 4.6 presents the mix of renewable energy for the base scenario. Existing plants dominate the market in the first two years of operation. New generation enters the market from 2004 onwards to take advantage of the higher level of demand through banking.

By 2010, about 15% of the annual renewable generation comprises generation above baselines for pre-1997 generators. A further 10% comprises renewable generation from upgrades of the large hydro-electric units and generation from plant commissioned between 1997 and 2001. Biomass and waste based generation projects comprise about 50% of the yearly generation. Biomass and bagasse are unable to meet the target by their own as they are constrained by a lack of fuel supply. These increase generation as more fuel becomes available. Wind is able to take up most of the rest due to its current under-utilisation is most regions.

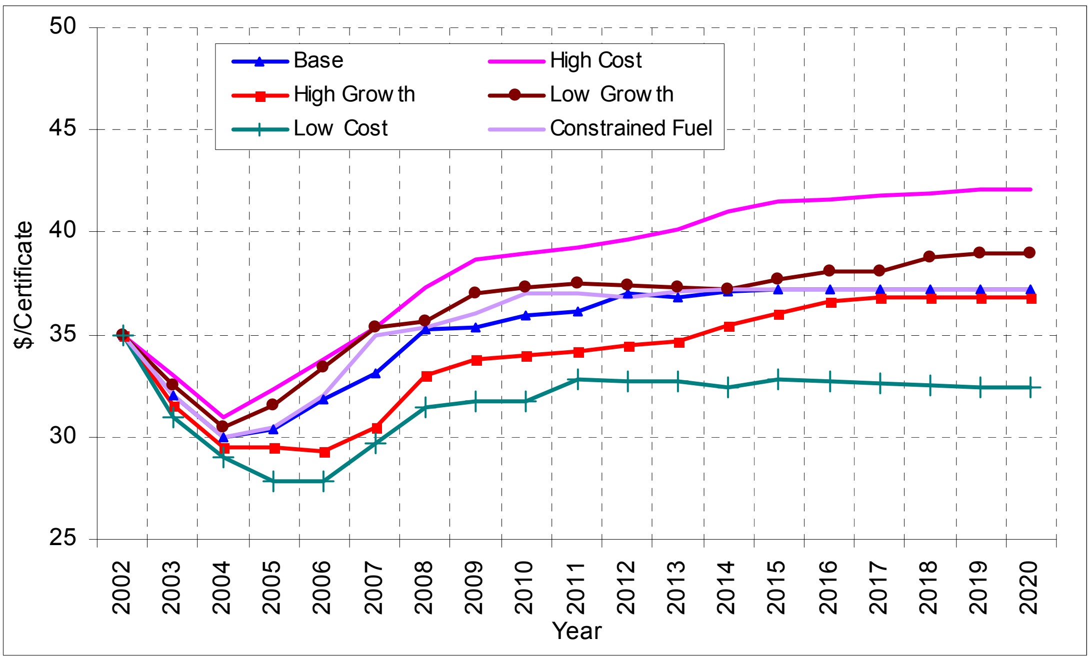
Figure 4.6: Renewable Energy Mix for Base Scenario



4.4 Other Scenarios

Four scenarios have been modelled in this analysis to test the sensitivity of prices to different market circumstances. Figure 4.7 presents the differing REC price paths under these different scenarios. In the period to 2010, prices are projected to range from $32/MWh to $39/MWh.

Figure 4.7: REC price paths for alternative market scenarios, $/MWh, real 2002 dollar terms



The High Growth Scenario represents a high growth in demand resulting in higher wholesale market prices. This will result in a lesser difference between the marginal cost of the new entrant generator and the wholesale market price. Consequently the REC price will be lower under this scenario.

The Low Growth Scenario represents a low growth in demand resulting in lower wholesale market prices. This will result in a greater difference between the marginal cost of the new entrant generator and the wholesale market price. Consequently the REC price will be higher under this scenario.

The High Cost Scenario shows the result of the cost of renewable energy becoming more expensive to commission. With a new entrant price for renewable generators being higher, the difference between this price and the wholesale market price will increase meaning higher REC prices.

The Low Cost Scenario shows the result of the cost of renewable energy becoming cheaper to commission. With a new entrant price for renewable generators being lower, the difference between this price and the wholesale market price will decrease meaning lower REC prices.

The Constrained Fuel Supply Scenario results in higher prices in the period to 2010. The higher prices are due to the fact that the levelised cost of biomass generation, which tend to set the certificate price in the period prior to 2010, increases as a result of the lower level of generation.

5 MARKET UNCERTAINTIES

In this Section, a number of issues related to potential certificate prices or the composition of renewable generation are examined.

5.1 Short-term influences on prices

The prices projected by our model for 2002 are lower than currently being offered in the market. The difference can be explained by a number of factors that have a temporary influence on the certificate price, but which are not included in the modelling. These factors are explained below.

5.1.1 Price history

Prior to the inception of the *Mandatory Renewable Energy Target* (MRET) program, an over-the-counter (OTC) market for trading RECs was established initially by a small number of market participants. At the same time many of those same participants became founding financial members of GEM, which was established as a REC exchange to facilitate seamless, transparent and efficient trade in the commodity. It is believed only a few transactions have been traded via the system, with the majority being traded via the OTC market.

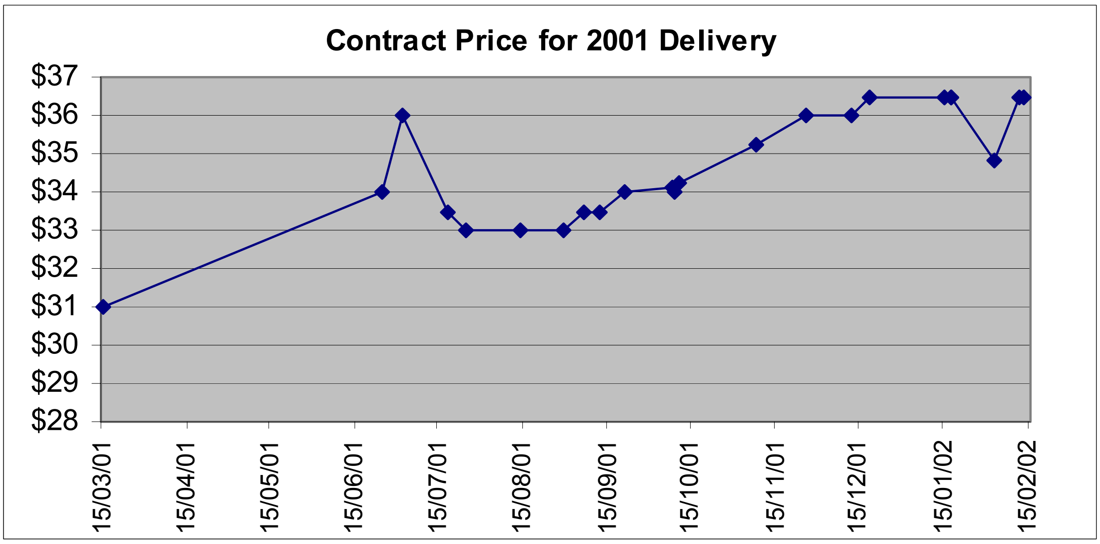
Retailer participants with MRET obligations have been able to gain price discovery both in the spot and forward REC market, with the latter going out usually three years.

Liquidity is gaining momentum as the market matures with parcels of five or ten thousand RECs now commonly traded in the spot and forward years. We expect this trend to continue as the MRET requirement ratchets upwards to the 9,500 GWh target. As the number of active participants grows, those seeking an avenue to either hedge MRET obligations, underwrite new green projects, trade or even accumulate stock, will welcome the increase in liquidity.

Market participants who have been involved in the electricity market have preferred ISDA style documentation for forward REC transactions. However for spot deals where no major issues such as credit risk are to be managed, bilateral arrangements have been sufficient.

Based on participants' feedback and market intelligence in the primary and secondary REC market it is estimated that a high percentage of the transactions was undertaken by brokers. Power purchase agreements (or PPA's) between generator and purchaser for a total package of electricity, green rights, RECs and carbon products are now beginning to find their way through intermediaries. We estimate that over 100 bi-lateral deals have been transacted in the market to date. The price curve for 2001 targets is shown in Figure 5.1.

Figure 5.1: Contract Prices for 2001 Targets



Source: NGeS

During the initial period after the establishment of the MRET program (1 April 2001) market observers were generally surprised by high REC prices achieved in the forward market. Expecting prices in the mid twenties, many commentators were surprised by the resilience of buyers and quickly re-rated their forward REC curves to show the contract outcomes from the bi-lateral market. Market participants not wishing to pay the penalty price of $40 per REC for non compliance, purchased RECs as high as $36.50 + GST leading up to the final weeks in 2001.

5.1.2 Participant trading strategies

Retailers

Retailers participating in the MRET program can be categorised into three groups under the headings of pro-active, re-active and compliant. Pro-active retailers, having established themselves early in the market as "green", now enjoy a position of strength. They forged relationships with major renewable generators by signing medium to long term (5–15 year) power purchase agreements (PPAs) prior to the mandatory and voluntary programs now in place. Renewable products including RECs were secured at the lower end of the price envelope and this group are in a net long position.

The second group and largest group of the three are the re-active or price takers. Having chosen a "wait and see" approach, this group missed out on the early bargains in the market place and now find themselves having to pay market price for PPAs or simply source their MRET requirement in the secondary market. Often this group buy from the first group at the top of the REC market and sell at the bottom of the REC market, a loss making activity, or use for their own liability.

The third group or compliant retailers are somewhat hidden to the general REC market and remain to the sidelines as they only require small numbers or under the MRET rules must provide RECs due to their unique down stream arrangements with supply. Participants in this category will come to the market just prior to surrender dates and purchase on the spot market, often paying a premium price.

Generators

Generators can be categorised into two groups, pure (those with just new renewable generation assets held) and mixed (those with new renewable generation assets plus pre-1997 renewable assets). Two listed renewable companies lead the field as pure renewable generators. Most of their dealings up to now have been by way of retailer PPA, but this might not be the case in the future as new projects come on line. Other smaller pure renewable generator companies are undertaking feasibility studies of their projects to get financing. To date, only a small number have succeeded to get financial close for their projects with the RECs being wrapped up in PPAs.

Forming the mixed category are the existing Hydros and a growing group of Government owned generators based in Queensland, New South Wales and Western Australia. Prior to 1 April 2001, these participants sold most of their RECs under PPAs to retailers for periods up to 10 years. However new project developers are holding onto some of the RECs past 2005 anticipating a shortfall. The large hydros up to now have been implementing strategies to satisfy retailers' demand and maintaining a position not to oversupply the market.

The modelling assumes that a competitive market exists, however there is some potential for participants to control significant quantities of the total renewable generation and exert market power on the clearing price. This could occur if a single player owning significant generation capacity held over large numbers of certificates for use in future years or delayed registering the certificates with the regulator. There is some evidence that this is occurring at the current time, with some generators becoming accredited but not yet registering certificates with the regulator.

Traders and other market participants

This group makes up the balance of players and provide the emerging REC market with liquidity and price discovery. The group is prepared to show two-way pricing for spot and up to three years along the forward curve. This group is also responsible in developing alternative derivative products with 'cash & carry', call & put options and repurchase agreements already common practice. The REC market is gaining credibility both among existing and intending parties and with further stock in the pipeline, should encourage new players from predominately the financial sector.

5.1.3 Key issues and price drivers

Emerging commodity markets generally follow in a similar evolution and the REC market is not different. Initially an absence of information combined with a small number of players, results in relatively large swings in both spot and forward price. Price drivers in the early stages are based around perceived supply and demand issues and in the case of RECs are currently supported by retailer direct purchases from small solar hot water systems and capped by the shortfall charge.

The key issue facing the market, however, is the level of 1997 base line for the hydro generators, which if too low will bury the REC market in its present form by flooding the market with surplus stock. A flow on will result in many possible renewable projects being placed on hold or abandoned as the extra revenue from the sale of renewable products including RECs is the difference between financial success or failure. This is discussed in more detail below.

Regulation is another driver that will cause both pain and pleasure for many participants depending on timing and direction. Already State based programs are fighting for a share of the action with draft legislation in the pipeline for carbon abatement products in direct competition with MRET. The review mid next year for the MRET program could alter the goal posts for non compliance and will be closely watched by all participants. A good example of recent regulatory change is SEDA's extension of their reporting period to align with Calendar years, causing an immediate shift in demand for spot RECs.

5.1.4 Forward curve influences

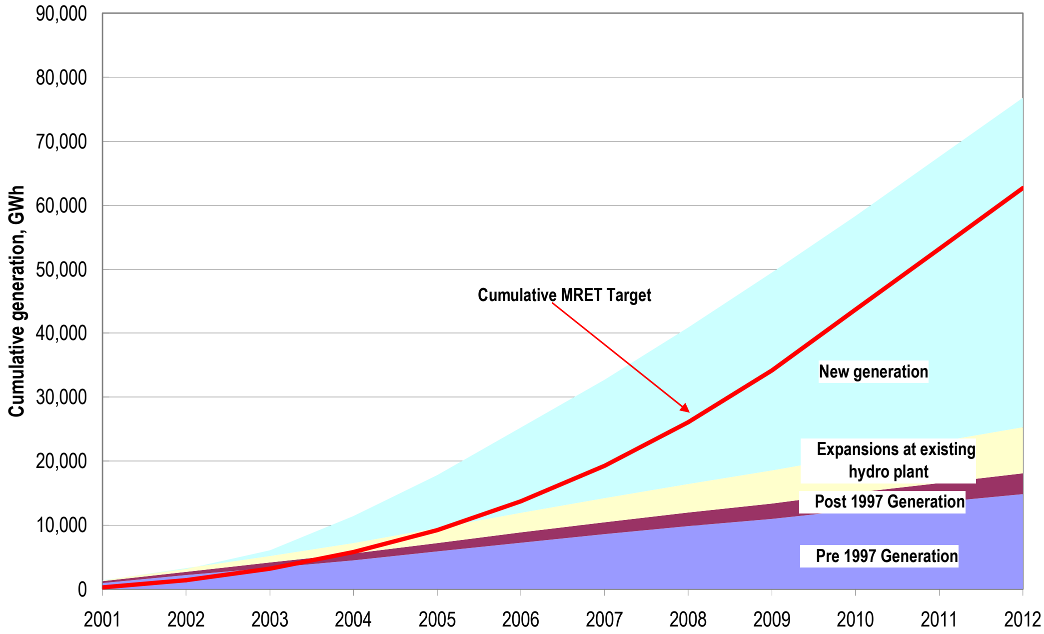
Ultimately environmental concerns will be the key influence on forward prices for renewable products. The global greenhouse movement will lobby Governments, companies and end-users to take action to reverse the perceived worsening greenhouse situation.

Locally, the REC forward price will be a function of two influences, governmental policy and economic reality. The market will ultimately find the appropriate level to do business both spot, medium term and long term. There will be winners and losers as with any asset market but the key will be information. Currently RECs are priced in a band between $34 and $37 going out three to five years with $38 available for 10 years with certain conditions. A floor in the REC price seems to emerge around $28 - $30 with the capital market seeking a safe haven for superannuation funds to participate in this growing asset class.

5.2 Baselines for existing generators

Debate has recently focussed on whether the MRET Scheme will enable new generation to enter the market place. Analysis undertaken by the Australian Ecogeneration Association suggests that additional generation from existing plant are sufficient to reach the MRET target until 2008. As shown in Figure 5.2, our analysis indicates that new generation would be required from 2004 onwards.

Figure 5.2: Projections of additional renewable energy generation by source, GWh



Pre-1997 generation equals generation above baselines for plant commissioned prior to 1997. Post 1997 generation is generation from plant commissioned since 1997. Expansions at existing hydro plant covers additional generation from existing hydro-electric generators brought about by upgrades or improved management practises.

Explanations for the differences in results include:

- The AEA analysis appears to exclude the impact of banking, which provides a significant incentive for generators to enter the market earlier than required to meet the target. If no banking was assumed, then our analysis would indicate that new generation would not be required until 2006.
- We have a lower component for over generation (above baselines) by existing hydro-electric plant in the good years for the following reasons:
  - It is very difficult to forecast the average inflows. AEA have just used a simple average output number, which does not consider that annual inflows do not follow any simple pattern.
  - In bad years, the hydro plant will have less to bank (compared to our estimates). For Hydro Tasmania, some generation above base lines is still possible in low rainfall years utilizing water stored in their large storages.
  - There is not a perfect correlation between the overs and unders across the different hydro-electric systems (i.e. there appears to be some compensation between hydro catchments).
  - If the hydro-electric generators have entered into contracts for the supply of RECs, they may be encouraged to use the overs to meet contract commitments in low rainfall years.

- We have assumed existing hydro-electric plant will now have the incentive to expand capacity up to 10% of the long-term average output, ramped up from 2% to 10% over 5 years. This is not all done at once because the hydro-electric generators cannot afford to have large chunks of their generation out all at once.

Our analysis indicates that existing renewable generators will have an important influence on the market over the next two to three years. Their trading strategies will have a significant influence on certificate prices over the next few years. But their influence on the market is likely to wane from 2004 onwards as new renewable generators enter the market. There is a probability that some existing generators may continue to exert some market power if they own a large proportion of the new renewable generation that enters the market.

5.3 Influence of green energy market

Green Power is a product retailed to consumers comprising electricity sourced from accredited renewable generation. Because of the high cost of renewable generation relative to conventional generation, Green Power is usually sold at a premium. The advent of Green Power allows retailers to differentiate sales of electricity, allowing them to potentially earn higher returns on Green Power sales and to enable them to develop a brand identity (through the sale of environmentally friendly electricity).

Green Power schemes consist mainly of consumption based schemes, in which a premium is charged on the price paid by consumers on some or all of the electricity consumed. An example is Energy Australia's Pure Energy Scheme, which allows consumers to nominate a percentage of their electricity (25%, 50%, 75% and 100%) to come from renewable sources.

Take up rates for consumption based schemes vary from 0.35% to 1.20%, whilst for contribution based schemes they have varied from 0.01% to 1.40%[3]. In NSW, about 28,913 domestic and 974 commercial customers purchased Green Power through consumption-based schemes as of 30 June 1999[4]. Once the varying contribution levels are taken into account, the renewable energy purchased is equivalent to that consumed by about 19,974 domestic customers. About 15,346 customers supported contribution based schemes.

Sales of Green Power have been generally less than the renewable energy purchased by retailers (see Table 5.1). Of the renewable electricity purchased, only about 22% has been on sold to consumers under Green Power Schemes.

Table 5.1: Purchases and sales of renewable generation under accredited Green Power Schemes in Australia, 1998/99, MWh

Type	Energy Purchased		Energy Sales	

3 C. L. Sonneborn, S. Russell amd C. Crawford Smith (1999), *Greenpower in Australia*, Australian CRC for Renewable Energy Occasional Paper, Perth, February. Pp. 7

4 ERM Mitchell McCotter Pty Ltd (2000), Green Power Annual Compliance Audit, Report to the NSW Sustainable Energy Development Authority, Sydney, July.

	Existing generators	New generators	Existing generators	New generators
Wind	2	8,763		
Solar	22	698		
Hydro	404,777	7,699		
Biomass	81,967	111,830		
Total	486,768	128,989	96,136	39,689

Source: ERM Mitchell McCotter Pty Ltd (2000), *Green Power Annual Compliance Audit*, Report to the NSW Sustainable Energy Development Authority, Sydney, July, pp. 2.5.

Based on discussions with the Sustainable Energy Development Authority and various retailers, the renewable energy scheme would work to reduce sales of Green Power. However, the market for Green Power would still exist, albeit at a reduced level. In our analysis, we assumed the demand for Green Power would reduce to the proportion of sales for pure renewable energy under current Schemes.

A key assumption is the premium for Green Power generation. Estimates of the Green Power premiums that are currently charged to customers were obtained from the retailers. Average premiums for each state have been calculated from these values and are presented in Table 5.2 along with the estimated value of the premium to the generator assuming a 75% premium share between retailer and generator. Premiums have been assumed to decrease at the average rate of decrease in the technology costs of the renewable energy generation projects of 2% per annum.

Table 5.1 Green Power premiums available to generators

Region	Green Power Premium (c/kWh)	Premium to Generator (c/kWh)
NSW	2.94	2.20
ACT	3.00	2.25
Victoria	3.50	2.63
Queensland	2.00	1.50

Source: SEDA NSW

Diversion of renewable generation to Green Power schemes results in higher prices for renewable energy certificates. However, because of the small amount of Greenpower sales, the impacts are small with certificate prices being at most 5% higher than they would otherwise be.

The diversion to Green Power sales also impacts on the pattern of generation over time and the mix of generation between renewable options.

5.4 Longer term uncertainties

In Section 4.4, a number of projections of renewable certificate prices are presented based on alternative assumptions on key drivers. The long term uncertainties affecting the prices are discussed in more detail below.

5.4.1 Costs of renewable generation

There are two sources of supply uncertainty. First, generation from some renewable energy options is intermittent. This affects the reliability of supply and the prices received for the energy. Depending on the penalty for non-compliance, the unreliability of supply may also lead to a high level of renewables being required in order to guarantee the targets are achieved. Risk averse retailers may over contract in order to ensure they can meet their targets taking into account the probability that the renewable generator may not generate the contracted quantity due to adverse climatic conditions.

Data on the level of variability of renewable options are sparse. The two most affected technologies are wind and hydro-electric generation. Preliminary data on wind generation indicates a variability of plus or minus 10 per cent. Variability in hydro generation is about plus or minus 11 per cent based on data from the Snowy Mountain Scheme and the HEC.

However, the impact of intermittent supplies on renewable certificate prices is likely to be minimal. The reasons for this include:

- Retailers can use the banking provisions of the scheme to bank some of the certificates in years when renewable energy generation is higher than expected for use in years when generation is lower than expected.
- Potential cross-correlation in the supply of renewable energy resources by type and location of the resources. Low wind generation in one region may be made up for by higher than average wind generation in another region or by higher than average generation by mini-hydro options. There is a dearth of data on the potential for cross-correlation in renewable energy supplies.
- Usage of biomass or co-firing options, which have more stable supply.

A second source of supply uncertainty is the potential limit on the availability of renewable energy resources due to economic or technical circumstances. For example, some renewable energy resources are only available for limited periods during the year. Bagasse is only available during the sugar cane harvesting period of May to November. The cost of the renewable energy is increased not only because of the lower level of utilisation but also because the outputs are typically sold in the lower price periods in the electricity market. Storage facilities to enable year round usage of bagasse would add to the cost of bagasse based generation.

Limits on the production of renewable energy technologies, which would affect the uptake of renewables over time, would also impact on prices. For example, Australia has a limited capacity to manufacture solar hot water heaters, limiting their uptake in the earlier years of the scheme.

Because many of the biomass fuels are byproducts of other productive activities, their availability is subject to economic factors affecting those activities. For example, bagasse is a by-product of sugar cane production and the amount of sugar cane crushed. Supply of sugar cane is variable due to the variability of sugar prices on world markets.

The future costs of renewable projects depends on the forecast reductions in capital prices resulting from technological improvements, the value of the relevant exchange rate and the ability of the project to obtain additional government support.

Obviously changes to these costs from those assumed would have a significant impact on prices. Higher capital costs would impact on prices, particularly in the latter period of the scheme when high capital cost options are setting the certificate prices. Increase in fuel costs will also have a moderate impact on prices. This is because such cost increases would increase the cost of biomass generation options as well as change the profile of generation to higher cost options such as wind generation.

5.4.2 Electricity market prices

The REC price is closely related to the electricity pool price in each market region. Any uncertainty in the wholesale price then flows through directly to the REC price that an individual project requires. This could result in changes in the REC price forecasts as well as changes in the mix of projects installed to meet the targets.

The outlook on certificate prices shown above was based on the assumption that wholesale prices would be at levels at least around long-run entry costs. But with new generation coming on-stream, some downward pressure on prices could occur, particularly in Queensland over the next few years where there is some 2,500 MW of new conventional generation coming onstream. On the other hand, there is emerging evidence of increased strategic bidding by incumbent generators forcing prices above new entrant levels.

5.4.3 Regulatory changes

The Mandatory Renewable Energy Scheme is to be reviewed in 2003, and a number of potential outcomes of this review could impact significantly on the price of certificates. The scope of the review is open and outcomes could potentially include:

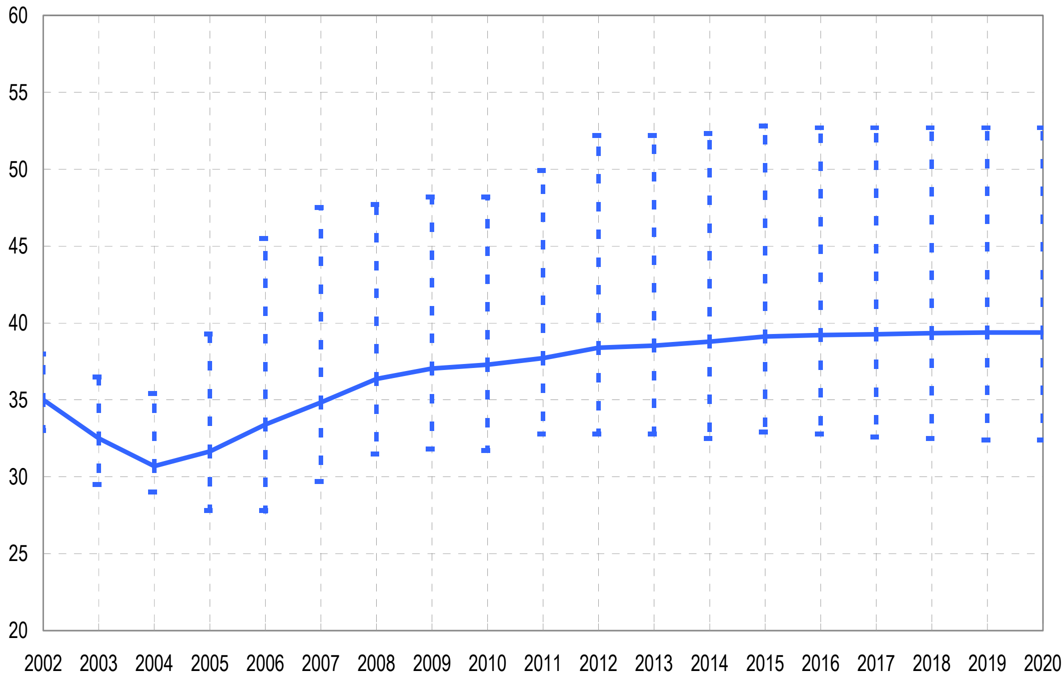
- Increasing the targets, resulting in increases in REC prices as more expensive options would be required to meet the targets.
- Increasing or indexing the penalty charge, if the penalty charge is used to a large degree by liable parties it would be assumed that the scheme was not working efficiently and increasing it would increase the REC demand above that observed if liable parties were paying the charge instead of buying certificates.
- Introducing requirements for proportional representation of particular types of renewable generation, if individual targets for say wind or solar generation were introduced the market would effectively be split into a number of discrete sub-markets with their own significantly different clearing price. This would result in the remainder of the market clearing at a lower price than that predicted.

All these changes could lead to higher REC prices than we have projected above.

5.4.4 Likely range of prices

Determining certificate prices is a complex task. Many factors affect price outcomes both in the short and long term. The market has yet to mature, so there are no clear market signals yet to base projections. Using our model of the certificate market and a range of possible assumptions on key variables, potential upper and lower bounds for certificate prices are shown in Figure 5.3.

Figure 5.3: Expected and likely range of REC prices, $/MWh, real 2002 dollar terms



The significant fluctuations in price come from both short and long term uncertainties. The fluctuations over the next two years come mainly from short-term fluctuations (such as constraints in resource availability and trading strategies), whilst those from 2004 0nwards, reflect long-term uncertainties such as the structure of the scheme, costs of generation and prices in the wholesale electricity market.

APPENDIX A: ASSUMPTIONS FOR THE NEM

A.1 Introduction

Details of the assumptions used in the simulation modelling of the NEM are provided in this Appendix.

The simulation model includes 9 regions: South Australia, Tasmania, Victoria, Snowy, NSW, Tarong, South Queensland, Central Queensland and North Queensland. MMA does not consider that the single Queensland region is suitable for providing appropriate signals for regional investment in new capacity or for ensuring efficient dispatch. It is also necessary to retain these limits in the market modelling to obtain a realistic estimate of the likely constraints on generation in Central Queensland. By modelling these regions and the impact of new generation on power flows, we also can indirectly model the effect of resulting changes in Marginal Loss Factors.

A.2 Demand forecasts

The demand forecasts adopted in this study were taken from the 2001 NEMMCO Statement of Opportunities (SOO). The National Institute of Economic and Industry Research (NIEIR) originally developed the forecasts. The 10% summer peaks for 2001/02 summer for NSW, Victoria and SA were subsequently amended by NEMMCO in June 2001. MMA estimated corresponding changes to the 50% peaks. MMA has further adjusted the forecasts as presented in the SOO to add back in the "buy-back" component of the embedded generation (especially the component contributed by renewable energy generation). This energy component is explicitly included in MMA's simulation model for the proposed renewable energy projects. The resulting forecasts for sent-out energy and peak demand are shown in Figure B.1. The peak demands shown are at the 50% probability of exceedance (but we include the 10% and 90% probability of exceedance forecasts in the model as part of the stochastic elements of demand).

The demand forecasts adopted are consistent with the forecasts published by the ESAA.

A.3 Supply characteristics

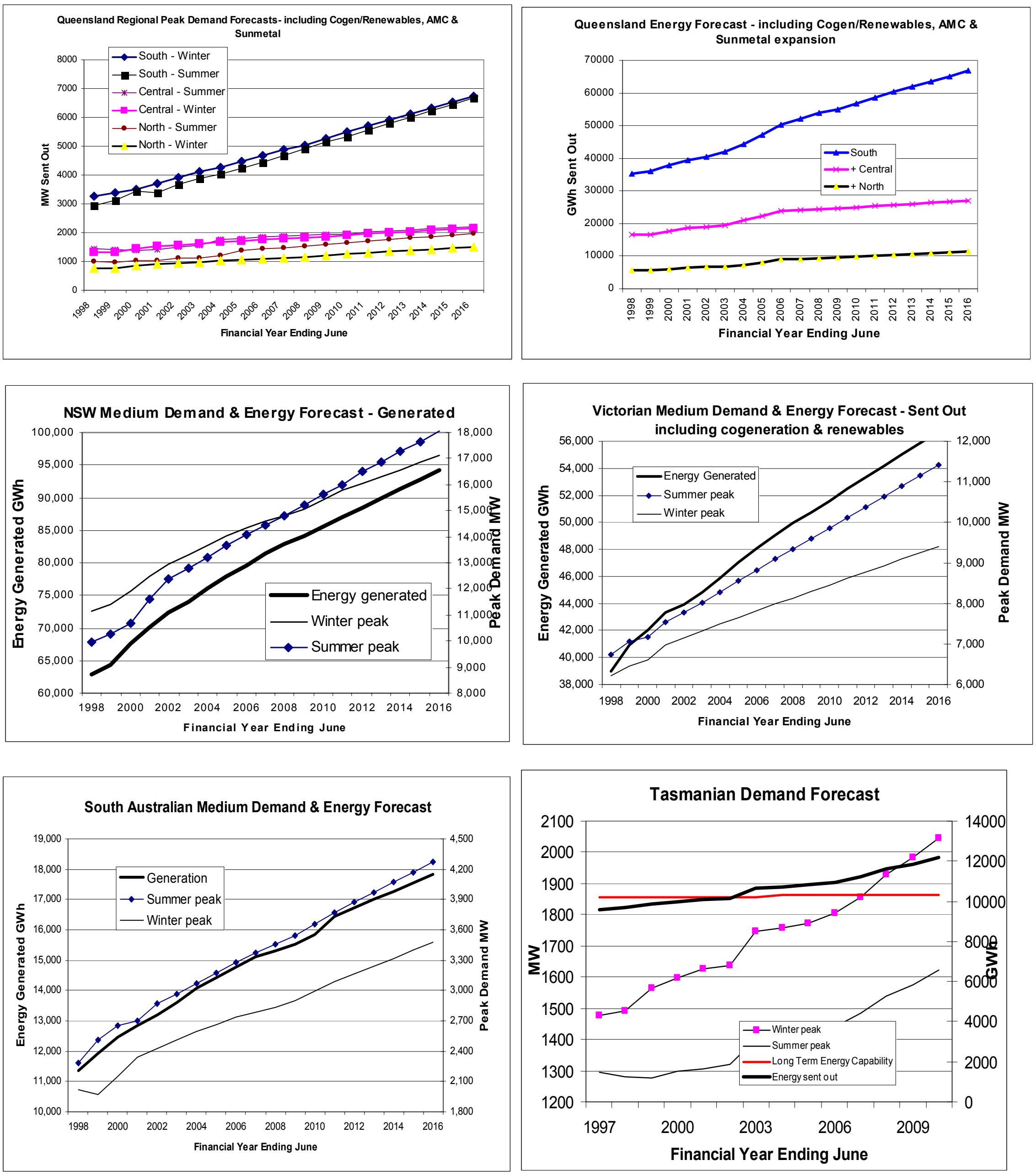
Marginal costs

The marginal costs of thermal generators consist of the variable costs of fuel supply including fuel transport plus the variable component of operations and maintenance costs. The indicative variable costs for various thermal plants are shown in Table B.1. We also include the net present value of changes in future capital expenditure that would be driven by fuel consumption for open cut mines that are owned by the generator. This applies to coal in Victoria and South Australia.

Table A.1: Indicative Average Variable Costs for Thermal Plant

Technology	Variable Cost $/MWh	Technology	Variable Cost $/MWh
Brown Coal – Victoria	5 - 8	Brown Coal – SA	8-10
Gas – Victoria	30 - 165	Black Coal – NSW	15 - 20
Gas – SA	25 - 39	Black Coal - Qld	10 - 16
Oil – SA	180-200	Gas - Queensland	29 - 46
Gas Peak – SA	112-127	Oil – Queensland	160

Figure A.1: Medium Growth Forecasts Sent Out



Plant performance

Thermal power plants are modelled with planned and forced outages with overall availability consistent with indications of current performance. Coal plants have available capacity factors between 86% and 95% and gas-fired plants have available capacity factors between 87% and 95%. Capacity, performance and heat rate data sent out are shown below.

Mothballing of plant

Macquarie Generation mothballed two Liddell units in mid 1998 and Delta Electricity mothballed the remaining two Munmorah units, although they sometimes run one unit when Vales Point is out of service. For pool modelling purposes we assume that the Munmorah units are not run and that these units stay out of the market until NSW prices firm above $33/MWh time-weighted prices. This level is based on statements by NSW generators and MMA's indicative assessment.

New renewable energy

The Commonwealth Government's policy to achieve 9,500 GWh of additional renewable energy by 2010 has been implemented with a maximum penalty for non-performance of $40/MWh. This penalty would effectively provide a cap on the premium available for renewable energy. Whilst the Government has developed a ramp-up target schedule for each calendar year, a certificates banking regime will stimulate earlier development of such projects.

Our assumptions regarding renewable generation are discussed in Appendix C.

New conventional generation

MMA's basic assumption on new entrants is that committed new entrants proceed as planned. Additional new entrants depend on market needs - essentially new entry is justified when post pool prices are adequate to recover avoidable costs and ensure an adequate return to capital. The type of new entry (base, intermediate and peaking) is determined as part of the simulation exercise.

Queensland

Committed plant in Queensland includes:

- The first unit of Millmerran in May 2002 followed by the second unit in October 2002.
- Tarong North Unit 1 (450 MW) is commissioned in mid 2003.
- 380 MW Swanbank E Combined Cycle plant (November 2002)
- A gas-fired generator in Townsville as planned by the Queensland Government (2004/05)

The timing of other new entrants in the ten-year study period for each scenario will be determined as part of the modelling output.

NSW

NSW has surplus mothballed plant and does not require new capacity until 2008-09. The choice of new entrants is between return of mothballed plant, new cogeneration projects and gas-fired peaking plant.

Victoria

At Bairnsdale in Eastern Victoria, there is a 40 MW gas turbine unit just commissioned that is required to meet network constraints between 1am and 3am on the 66kV network east of Morwell during the hot water heating peak. The unit is gas fired and will also be available to operate on hot summer days. Duke Energy has installed a second unit for peaking purposes by the 2001/02 summer.

Edison Mission Energy has commissioned 6 * 50 MW open cycle plant (300 MW total) in the Latrobe Valley based on second-hand gas turbines from Contact Energy in New Zealand. AGL is developing a 150 MW open cycle plant at Somerton, also timed for service in 2002.

The AES Golden Plains project has been omitted because these two plants provide sufficient capacity for the next two years and AES are facing strong local opposition. Further demand growth is expected to be covered by augmentation of the Snowy to Melbourne transmission system and by Basslink.

The choice of other new entrants in Victoria is limited to gas-fired plant, either combined cycle plant or peaking plant.

South Australia

With the completion of Pelican Point by April 2002, South Australia will have new capacity requirement of nearly 600 MW by 2009/10. However, with the completion of Murraylink and the projected refurbishment of Playford and the commissioning of Quarantine, Hallett and the expansion at Snuggery and Mintaro by ANP, there may be no need for new capacity in the near term.

For additional new entrants, we would also expect open cycle to be more highly favoured except for the existing limited capacity and high cost of augmentation for maximum daily gas transmission capacity into South Australia. The high cost of gas transmission capacity would appear to favour the higher efficiency of combined cycle plant if the commitment to the Pelican Point project is a guide. However, if the Otway to Adelaide gas pipeline proceeds there may be a period when spare gas transmission capacity enables a new peaking plant to be economically feasible. The Australian National Power proposal for a new gas turbine is an example of such an opportunity.

Murraylink was scheduled for April 2002 but is likely to be delayed until later in the year. We have assumed initial operations from July 2002. The TransGrid SNI project is now planned to proceed - we will assume the committed start date announced by the proponents.

New entry costs

New entry costs are assumed to provide a cap on future market prices because:

- High pool prices will drive up contract prices and provide scope for new entrants to enter the spot and contract markets and take away market share from all participants and volume from the higher cost participants who are likely to be setting the high prices.
- Prices consistently well above new entry costs would prompt regulatory intervention due to perceived market failure.

Tables A.2 show MMA's assessment of likely new entry costs. These costs have been based on an estimate of the first year's revenue requirement to meet 9% interest plus allowing one-half of the annual depreciation based on a book life of 30 years for coal or 25 years for gas. This is equivalent to depreciation for a 60 year life for coal assets and a 50 year life for gas fired assets. We have assumed that gas fired plants would be located close to load centres with an MLF of 1.0 and that coal plants would have loss factors of 0.97. Availability of 90% for coal and 92% for gas-fired plant has been assumed.

This approach represents a pre-emptive new entry strategy as compared to using levelised new entry costs. These costs are only about $1 - $3/MWh below the levelised costs.

Table A.2: First Year New Entry Costs Assumed in Analysis, $/MWh

Financial Year Ending June	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
South Australia	42.11	41.93	41.75	41.78	41.81	41.85	41.89	41.94	41.98	42.04
Victoria	40.74	40.33	39.93	39.53	39.13	38.39	37.64	37.67	37.71	37.75
NSW	38.06	37.56	37.07	36.58	36.10	35.84	35.58	35.33	35.08	34.83
Queensland South	35.43	35.07	34.72	34.38	34.03	33.77	33.51	33.25	32.99	32.74

New plant was installed in the year when close to these prices could be sustained after service.

Gas prices

Existing market prices will be assumed for gas prices in all regions of the NEM. The exception is Queensland, where gas prices are projected to reduce substantially if a new source of abundant gas becomes available.

Table A.4: Gas Prices for Power Generation ($June 2002)

Region	Indicative Gas Price

South Australia	Full gas price of $3.25/GJ declining to $3.15/GJ by 2016/17.
Victoria	Full $2.90GJ, GJ staying flat in real terms until 2007 and then reducing by $0.10/GJ.
NSW	$3.30/GJ full inflating at 95% of CPI until 2006 when both drop by $0.10/GJ.
South Queensland	$3.50/GJ full until PNG, CSM or Timor Sea gas and then $2.85/GJ thereafter.

Interconnect assumptions

Assumptions on interconnect limits are shown in Table A.5. These limits are based on the NEMMCO 2001 Statement of Opportunities and the Powerlink 2001 Planning Statement. In some cases, MMA has added some interim capacity stages to represent the commissioning stages prior to commercial service. Such commissioning will depend on performing satisfactory system tests for dynamic stability over several months depending on being able to establish required system conditions.

Table A.5: Interconnection Limits

From	To	From Date	Capacity	Summer
Victoria	Tasmania	Jul-05	300 MW	
Tasmania	Victoria	Jul-05	600 MW	
Victoria	South Australia		500 MW	
South Australia	Victoria		250 MW(1)	
South Australia	Redcliffs	Sep-02	188.2 MW	
Redcliffs	South Australia	Sep-02	215 MW	
Victoria	Snowy		1000 MW(2)	
Snowy	Victoria	Jan-03	1900 MW	
Snowy	NSW		3000 MW	2500 MW
NSW	Snowy		1150 MW(3)	
NSW	South Queensland	Jul-02	180 MW(6)	
South Queensland	NSW		75MW(6)	56MW
NSW	Tarong	Jul-01	500 MW (7)	
Millmerran	Tarong	Aug-02	840 MW (5)	
Tarong	NSW	Jul-01	750 MW	
Millmerran	NSW	Aug-02	1000 MW (4)	
Tarong	South Queensland		2150MW - 2450MW	
From	**To**	**From Date**	**Capacity**	**Summer**
Tarong	South Queensland	Jul-08	2950 MW	
Central Queensland	South Queensland		1070 MW	

Central Queensland	South Queensland	May-02	1150 MW
Central Queensland	Tarong		750 MW
Central Queensland	Tarong	May-02	850 MW
Central Queensland	North Queensland		940 MW
Central Queensland	North Queensland	Jul-12	1440 MW

(1) Limits up to 300 MW are allowed in the model in the mild seasons

(2) Limits of 900-1000MW are consistent with a total Victorian export limit of about 1300 MW. The model uses 1000MW in the mild seasons and 900MW in the peak seasons. Previous experience has shown that this is consistent with a maximum total export limit of 1300 MW.

(3) Values between 850 MW in peak seasons up to 1150MW in mild seasons were applied in the model

(4) Tarong to NSW limit increases to 1000 MW when Millmerran commences service

(5) The transmission limit from Millmerran to Tarong is understood to be limited to 840 MW for sudden loss of the interconnection.

(6) Directlink is assumed to allow 190 MW to flow to Queensland in winter, 180 MW in summer and allow 75 MW to NSW in winter and mild seasons and 56 MW to NSW in summer.

In the case of the transfer limit from NSW to Queensland via QNI and Directlink, the capability depends on the Liddell to Armidale network, the demand in Northern NSW and the limit to flow into Tarong[1].

TransÉnergie is committed to its Murraylink project, a 200 MW HVDC interconnection between Redcliffs in Victoria and a new Monash substation in South Australia near Berri for service by April 2002. We assume that this project proceeds in accordance with these public statements, although on the basis of the construction of Directlink and delays in gaining planning approval, we would expect full service somewhat later. We are assuming commissioning to commence in July 2002 and is completed by 1 December 2002.

There are number of other possible interconnection developments to be considered:

- A 480 MW capacity Basslink between Victoria and Tasmania for service by July 2005.
- The construction of a new 200 - 250 MW interconnection between Southern NSW and South Australia, the "SNI" HVAC option.
- An upgrade of the existing Victoria to South Australia export limit from 500 MW to 650 MW by additional transformation at Heywood Terminal Station (described as augmentation of the "Heywood interconnection"). This project is now referred to as Southern Link by TransÉnergie and replaces its earlier 65 MW HVDC option given this name.
- A 400 MW or 800 MW upgrade of the Snowy to Victoria transmission link which would enable additional imports from Snowy/NSW into Victoria. This is referred to as SnoVic.

The Tasmanian Government is actively pursuing Basslink. In February 2000, it was announced that National Grid Company was selected as the preferred developer with a target date for service of early 2002. The link will have a continuous capacity of 480 MW and a

1 There is currently expected to be a limit of 840 MW for flow into Tarong. This is not a fixed limit and could be increased with additional load shedding in Queensland.

short-term rating up to 600 MW. Some delay could occur as a result of the need to address environmental issues. Commercial service is currently planned for mid-2005.

In modelling the NEM, apart from committed upgrades (Murraylink, Snovic, SNI and Basslink) additional upgrades of interregional transmission will be determined as part of the modelling process. In the analysis, we assume any additional interconnection will be non-regulated and will be chosen in competition with new generation options. That is, the modelling will determine the least cost outcome under each settlement scenario.

Value of Lost Load

The Value of Lost Load ("VoLL") is the cap on spot market prices. It was increased from the current $5,000/MWh to $10,000/MWh on 1 April 2002. VoLL is a factor in estimating expected spot prices having regard to the risk of load shedding based on the forced outage rates and capacity of thermal units and the prevailing demand. As such, a higher VoLL is expected to advance the timing of new entrants and to result in higher expected market prices prior to new entry. The above value was applied in our pool model in nominal terms for three years and then escalated back to real value.

Inter-regional losses

Inter-regional marginal loss factors in the simulation model are based on step wise linear functions of interconnection power flow. They have been estimated from equations published by NEMMCO and Powerlink for the NEM regions and Queensland zones. We have used typical values of regional demand for system conditions when each link might be limiting. The model provides for a different stepped loss ratio for each direction of power flow. In order to model the losses solely as a function of the flow, we have adopted typical values of NSW, Victorian and SA demand for the direction of power flow.

Intra-regional losses

Intra-regional losses were applied as detailed in the NEMMCO March 2002 Report "Marginal Loss Factors for 2002/03 Fiscal Year". This factor is a divisor on the generator bid provided in PLEXOS and is the bids are adjusted to include the effect of the Marginal Loss Factors to refer them to the regional reference node.

Queensland Energy Policy

The Studies will be adjusted to ensure that there is sufficient gas fired generation from 1 January 2005 to meet the 13% target for gas-fired generation delivered to Queensland. The calculation of the 13% will be based on the following interpretations of the statements so far produced by the Queensland Government:

- We shall assume that the 13% will effectively be applicable to sent-out generation. This is a simplifying assumption because the distribution and transmission loss factors and their use have not been released.

- We shall assume that Boyne Island, AMC, QAL (750 GWh) and Sun Metals (800 GWh) are not liable loads under the scheme as they use more than the 750 GWh limit.
- We shall assume that Yabulu converts to cogeneration and that Mt Stuart OCGT and Townsville run at 85% take-or-pay generation volume. When the 13% target is achieved, Kogan Creek follows as the next project.

If there is insufficient gas-fired generation to meet the target, we shall assume that Gas Electricity Certificates will have a net value and this will reduce the bid price of gas-fired generators as if they had a negative marginal cost component. This would be expected to reduce energy prices to a small degree.

The gas fired generation ratio will be estimated as equal to:

Ratio = (Gas Fired Generation Sent–out +BP Cogen)/(Queensland Sent-out Generation + BP Cogen – BSL – AMC - QAL – SunMetals + Qld Import - Qld Export)

Where:

- Queensland sent-out generation = sent-out generation from all Queensland power stations modelled in MMA's NEM model including sent-out generation from renewable energy projects.
- BP Cogen = the output from the BP refinery plant assumed to be 252 GWh (32 MW * 90% * 8.76)
- BSL = the BSL load in GWh
- AMC = Australian Magnesium Corporation load supplied by Stanwell
- QAL = Queensland Alumina Ltd assumed to be 750 GWh
- SunMetals = 800 GWh plus the assumed expansion

The BP Cogen is not included in the Strategist model and therefore its output needs to be added. The denominator represents the liable loads referred back to sent-out generation.

A.3 Modelling of Market Prices

Pool prices are determined within the model based on thermal plant bids that are derived from marginal costs or entered directly. The model generates average hourly marginal prices, having regard to all possible thermal plant failure states, for each hour of a typical week for each month of the year.

We assume the current market structure continues under the following arrangements:

- Victorian generators are not aggregated;
- NSW generators remain under the current structure in public ownership;
- The ownership structure in Queensland remains;

- The SA assets remain privatised under the current portfolio groupings (Optima in the TXU portfolio and Synergen in the National Power portfolio with Pelican Point and Hazelwood Power)

In the simulations undertaken for this study, Cournot bidding pricing was assumed. That is, generators bid in their portfolio of generating assets to maximise profits subject to prices not breaching the long run average cost of new generation.

APPENDIX B: STAKEHOLDER CONSULTATIONS

B.1 Introduction

During this study, MMA held a number of discussion sessions with individual companies. The objective of these sessions was to consult with key participants to gather information about the RECs market directly from participants and to ensure that we have the most up-to-date information in modelling the price path.

Informal consultation sessions were held with key market players representing generators, retailers, traders and brokers. The following discussion summarises the major issues raised by these participants. The issues include resource availability, participant behaviour and their understanding of the scheme, their successes and other issues of concern in relation to REC market and prices including restrictions impacting on the choice of renewable generation (eg: market restrictions on native wood waste generators, environmental restrictions on sites of wind generation, etc.).

B.2 Key findings

Success

In general, participants believe that apart from some of the operational issues in the early stages relating to accreditation and creation of RECs and baselines for hydro generators, the new market is very successful due to:

- Participants understand how the market works.
- The mechanism for trading is in place; for example brokers and GEM. Although it is recognised that trading has been slow due to the low volume required for 2001.
- Its simplicity and good design.

Existing Baseline

The existing 1997 baseline issue has been considered a major concern for liable parties as they believe that the historical base lines credited to the hydro generators provide them with a strong market position to manipulate the supply of RECs. However, hydro generators face uncertainties in making sure that their generation output meets their contract position for the RECs market.

Hydro generators have been able to implement water management and generator efficiency strategies to improve their generation above their baseline. For example, Southern Hydro has been very active in improving its generation to produce RECs and is planning to further expand this strategy as was published in their recent press release.

The market believes that Hydro Tasmania have accumulated more RECs than what was anticipated at the inception of the market because of the effect of their historical base line assigned to theme under the scheme.

Market Reaction to Prices

The general feedback from liable parties is that although prices started in the mid to high $20s, prices firmed up at around $33-$36. As it was the first year of the RECs market, liable parties were focused on meeting their targets and were prepared to pay the higher prices as the prices paid for the small volumes required to meet their targets did not create for them high risks positions. As more RECs are registered and banked, because the RECs are a storable commodity, the market expects volatility of prices to be dampened.

Key Economic Drivers

Market participants are represented by public and private ownership. They have different key commercial drivers. Government owned enterprises with low WACC and different commercial drivers (e.g. low discount rates) respond differently from privately owned companies with higher commercial performance levels.

Some of the participants are planning to purchase RECs from the market in the initial years and then cover their liabilities from renewable energy projects.

MRET Review in 2003

The scheduled review creates a number of uncertainties for market participants which include:

- Increase of target to more than 9500 GWh.
- Indexation of penalty payment.
- Availability of RECs to meet targets beyond 2003 and lack of information for price discovery.

New Entrants

Existing producers are the dominant players in the market. New entrants are expected to produce RECs at higher prices to achieve their revenue targets.

RECs Market Liquidity

Trading of RECs in the energy related financial market has shown slight liquidity due to the fact that the market is in its infancy stage reflected by the low targets required by the liable participants. Participants believe that the review in 2003 contributed to the slower than expected liquidity of the market. This position is expected to change in 2004 once the review outcomes are known and implemented.

Some of the participants are not taking forward positions until there is more certainty on the issues to be considered in the review.

Banking

One of the strong features of the MRET scheme is that RECs can be banked from one year to another. The forward price curve should take into account the cost of carrying RECs from one year to the next. This has not been evident in the market due to the different rate of return required by government and privately owned generators. Some participants believe that there are many more RECs generated than the numbers registered and are being banked