Final Report to

WA Office of Energy

Impacts of a Renewable Energy Target for 2020 on Electricity Markets in Western Australia

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ABBREVIATIONS

CoPS	Centre of Policy Studies
GSP	Gross state product
HDI	Household disposable income
HDI	Household disposable income
IGCC	Integrated Gasification Combined Cycle Plants
IMO	Independent Market Operator
MMA	McLennan Magasanik Associates
MRET	Mandatory Renewable Energy Target
NAIRU	Non Accelerating Inflation Rate of Unemployment
NGGI	National Greenhouse Gas Inventory
NRET	NSW Renewable Energy Target
NWSJV	North West Shelf Joint Venture
RECWA	Renewable Energy Certificates Western Australia, which are created by eligible generators under the RETWA scheme
REMMA	Renewable Energy Market Model Australia
RETWA	Renewable Energy Target Western Australia
STEM	Short Term Electricity Market
SWIS	South West Interconnected System
UCC	Ultra Clean Coal
VOLL	Value of Lost Load
VRET	Victorian Renewable Energy Target
WEM	Western Australian Electricity Market

EXECUTIVE SUMMARY

Renewable energy is currently more expensive than fossil fuel based generation. The Western Australian Government is considering measures to encourage deployment of renewable energy technologies, and has a policy of developing strategies to achieve a higher share of generation for renewable energy by 2020. McLennan Magasanik Associates and the Centre of Policy Studies were commissioned by the Western Australian Office of Energy to examine the costs that a target for renewable energy generation may impose on the electricity sector and the broader economy.

For the purposes of analysis, it is assumed that a tradeable certificate scheme is implemented to achieve the target. Elements of the scheme are assumed to be:

- The renewable energy target will ramp up from 2010 to 2020. The percentage target will be converted into an energy (GWh) target.
- Retailers and large wholesale electricity customers will be required to source an increasing share of their electricity requirements from renewable energy sources. Self generated loads and energy intensive trade exposed industries will be excluded. Achieving annual targets will be demonstrated by the redeeming of certificates to cover a retailer's share of the target.
- Eligible renewable energy generators will be able to create certificates for each MWh of new renewable generation. Only generators commencing operation from 2008 onwards are eligible to create certificates. Existing renewable energy generators will be able to create certificates only on expansions of existing capacities.
- Eligible renewable energy generation covers hydro-electric, biomass, wind, wave, geothermal and solar/PV technologies. It is assumed that solar water heaters will not be eligible.

Three renewable energy targets by 2020 were analysed in this study: 10%, 15% and 20% of electricity demand in 2020. Targets are ramped up from an existing 6% target in 2010 to the ultimate target in 2020.

The method used to estimate impacts is described in the body of the report. The analysis is based on a database of renewable energy generation options available in Western Australia, with data on renewable energy generation capability and generation cost sourced from published data. Certificate prices and technologies chosen to meet the target are determined using an optimisation model that determines the mix of plant that meets cumulative renewable energy requirements at least cost. The certificate price is equal to the long run marginal cost of the last renewable energy plant required to meet the target, after other revenue (including revenue from sales of electricity on the wholesale market) are deducted.

Schemes to increase renewable energy generation affect the electricity market. Wholesale prices will be affected by the level and timing of entry of new renewable energy plant. Retail prices will also be affected by changes in the wholesale price, as well as the pass through of the costs of certificates. Higher levels of renewable energy generation will impact on fossil fuel generation and on the returns to existing generators. These impacts have been estimated using a simulation model of the wholesale electricity market, which determines the level of dispatch of generating plant that minimises the cost of suppling electricity to the market and also determines the choice of new plant to meet future load growth and replace existing plant.

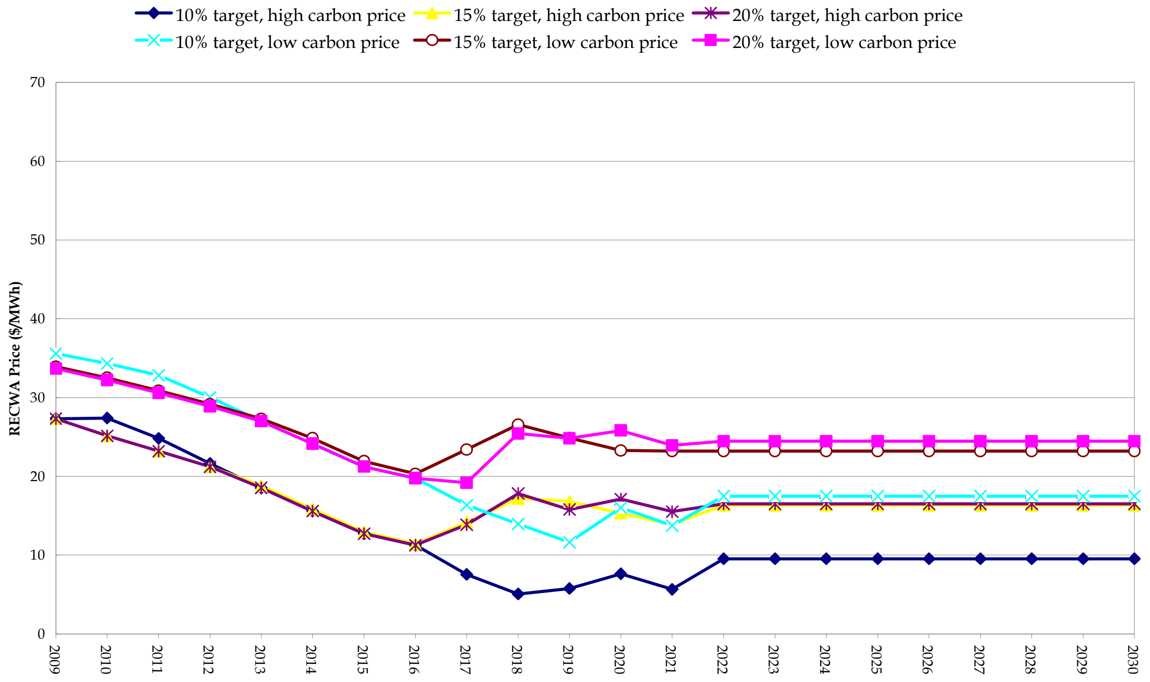
Assumptions are also detailed in the report. One key assumption is that it is assumed a national carbon emission cap is imposed on generation. This is represented in the modelling as a price for emitting greenhouse gases. Carbon price projections were agreed with the Office of Energy and are detailed in Section 2-4-2 (Policy related assumptions). The projections are derived from modelling undertaken by the National Emissions Trading Taskforce. Note this study incorporates the impact of a carbon price on the SWIS, it does not model the operation of an emissions trading scheme in Western Australia.

Carbon pricing serves to increase the price of electricity for consumers in business-as-usual scenarios. Consequently, the results and impacts of renewable energy targets presented in this report are additional to any impacts on the Western Australian electricity market or economy flowing from the introduction of the national carbon emissions trading scheme. Greenhouse emissions in the SWIS are projected to be lower as a result of renewable energy targets. However, the targets may not influence total abatement in the national emissions market (see Exhibit 1 in Section 3-2 for an overview of the carbon pricing assumptions on generation in the SWIS and the interaction with a renewable energy target mechanism and Appendix C for details of the results of a zero carbon price sensitivity analysis).

In all, eight scenarios were simulated to estimate the impacts. The scenarios were a combination of four renewable energy targets in 2020 (including the base case of a zero target) and two carbon price trajectories.

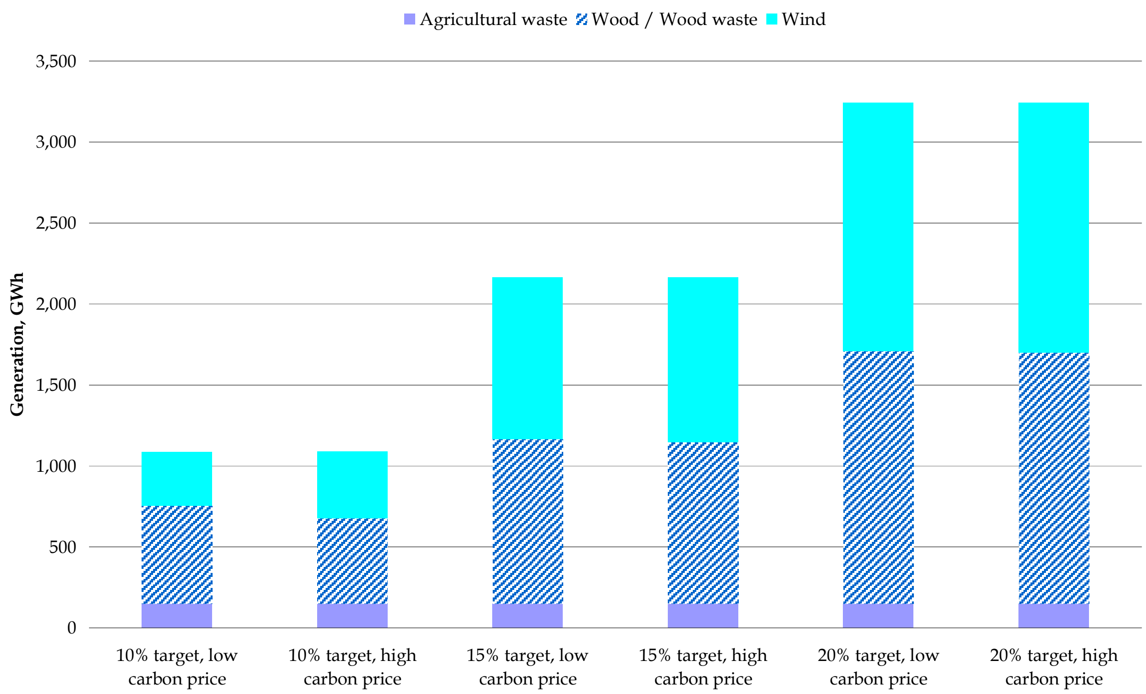
Under the proposed scheme, a market for renewable energy certificates is established to provide sufficient revenue for renewable energy generation to enter the market. Projections of the certificate price are shown in the following chart. For all targets, prices for certificates are initially high, but then drop over time as renewable energy generation costs fall and as wholesale electricity prices rise under the influence of an increasing carbon price. As expected, the higher the target, the higher the certificate price. Certificate prices are about $8/certificate lower with the higher carbon price, reflecting the higher electricity prices received by renewable energy generators (and hence a lower revenue gap required through certificate sales to meet the cost of renewable energy generation).

Figure 1: Renewable energy certificate prices



In most scenarios, a mix of wind and biomass generation is likely to be the least cost option to meet the targets. There are some low cost biomass options available, so that biomass dominates the mix with a low renewable energy target. The higher the target, the higher the proportion of wind generation.

Figure 2: Renewable energy generation by technology type



The renewable energy target will involve significant investments in new renewable energy generation, with estimates of the present value of the capital investment over the period to 2035 ranging from $477 million to $688 million for a 10% target to $1,500 million to $1,740 million for a 20% target. The investment is spread relatively evenly over the period from 2010 to 2020, indicating a prolonged period of development to enable the development of a renewable energy industry.

Implementing a renewable energy target has a complicated impact on wholesale prices (see Table 1). Although the total cost of renewable energy generation is more expensive than fossil fuel generation, wholesale prices were found to be lower with a renewable energy target when the cost of purchasing certificates was not included. The reduction in the wholesale price is caused by additional renewable energy capacity entering the market earlier than the market requires new capacity, thus prolonging an expected surplus of generation capacity in the short term and dampening prices.

Over the long-term, prices are reduced because of the lower short run marginal cost of renewable energy generation (which displaces plants with high short run marginal costs) and the deferment of the need for new fossil fuel plant (shifting the new entry cost curve outward in time).

When the cost of purchasing certificates is spread over all electricity sales, the cost of purchasing electricity on the wholesale market increases, with the increase ranging from 0.0% to 3.2% for a low carbon price and -0.4% to 1.3% for a high carbon price. The implication is that electricity consumers who are not liable under the proposed measure (the energy intensive trade exposed industries) will experience minimal change in prices and even lower electricity prices, whilst all other customers will experience a small increase in prices as a result of the need to purchase certificates. Retail price increases under the low carbon price scenario are approximately half of that imposed by the scheme in the absence of a carbon price (Appendix C).

Table 1: Wholesale and retail price impacts, % increase in business-as-usual levels

	10% Target Low Carbon Price	15% Target Low Carbon Price	20% Target Low Carbon Price	10% Target High Carbon Price	15% Target High Carbon Price	20% Target High Carbon Price
Wholesale price	-0.9%	-0.9%	-0.4%	-0.9%	-0.4%	-0.8%
Wholesale price with certificate prices	0.0%	1.5%	3.2%	-0.4%	1.0%	1.3%
Average retail prices	-0.1%	0.7%	1.7%	-0.4%	0.5%	0.7%

Source: MMA analysis.

Renewable energy targets had other important impacts on the electricity market:

- The level of coal-fired generation is lower than would be the case without the target, but the level of coal-fired generation continues to grow under most target scenarios, with the exception of a 20% target where the level of black coal generation remains steady until 2020.

- The level of gas-fired generation is generally slightly lower, although in some years it can be higher than without the target when new coal-fired plant have been deferred.
- As a result of the smaller growth in fossil fuel generation, the renewable energy target achieves further reductions in emission abatement. Abatement of greenhouse gas emissions in the SWIS as a result of this measure ranges from an average of 0.5 Mt per annum for a 10% target to 1.8 Mt per annum for a 20% target.
- The range of targets modelled increase the cost of electricity generation by between $158 million to $818 million assuming a low carbon price, and by $463 million to $1,156 million for a high carbon price. In the absence of a carbon price the cost ranges from $164 million to $612 million. The additional cost increases with increasing carbon price because although the mix of plant is similar and undiscounted capital expenditure in renewable energy generation is similar, the investment in plant is brought forward with a carbon price and therefore the capital expenditure on renewable energy generation is discounted less.
- Profitability for existing generators improves in aggregate for targets higher than 10%. Although wholesale prices are lower, the reduction is more than outweighed by the fact that higher renewable energy targets defer the need for new base load plant, thus increasing the volume of generation from incumbent plant.

Wider economic impacts were estimated using the Centre of Policy Studies MMRF model of the Australian economy for a 15 per cent renewable energy target. Details of the model are described in the report. The economic impacts were simulated by introducing the changes in the electricity prices estimated by the electricity market model and the change in pattern of generation between fossil fuel and renewable energy generation. The MMRF model determines the downstream impacts arising from the changes in these variables.

Estimates of the key impacts are shown in Table 2. Both Gross State Product and employment are expected to be less than 0.2% lower in 2020, as a result of a 15% renewable energy target. The renewable energy target delays the achievement of projected levels of economic activity by around two weeks in 2020. The annual reduction in GSP ranges from $5 million to $170 million in the low carbon scenario, and from $3 million to $120 million in the high carbon price scenario. Despite the lower rate of growth, the Western Australian economy is still projected to grow by around 3.8% to 4.1% per annum in the period to 2030. Even without a carbon price, the target has little impact on economic activity (see Appendix C).

Table 2: Economic impacts in Western Australia of a 15% renewable energy target in 2020, % deviation from business-as-usual

Variable	Low carbon price	High carbon price
Real private consumption	-0.08	-0.05
Real investment	-0.47	-0.25
Real exports	-0.01	-0.01
Real imports	-0.18	-0.10
Real GSP	-0.11	-0.07
Employment	-0.11	-0.05
Real wages	-0.02	-0.01

Source: CoPS.

Most industries experience a small fall in the value of output as a result of the renewable energy target. The largest fall occurs for the fossil fuel based electricity industry, the coal industry and construction and business services industries. All other industries experience falls in the value of output of less than $30 million over the study period. Some industries experience an expansion in output, mainly those industries which are not liable under the measure (trade exposed energy intensive industries), as these experience a fall in wholesale energy prices. The renewable energy industry also expands.

Thus, imposing a renewable energy target will have a small impact on electricity prices and an even smaller impact on economic growth and employment. This general result holds even in the event that no carbon pricing is introduced over the study period.

The targets are achieved at a greater cost of resources in the electricity supply sector, which is reflected in higher retail prices to liable electricity customers. These outcomes are summarised in Table 3. A renewable energy target will also deliver additional benefits that have not been quantified in this analysis. These benefits tend to be either non-pecuniary (e.g. lower emissions of harmful air pollutants), or may not be realised until well into the future (e.g. lower renewable energy costs in the long-term) and are difficult to quantify.

Table 3: Summary of impacts

	10%	15%	20%
Low carbon price			
Impacts			
Certificate price, $/certificate	20.1	24.7	25.1
Wholesale electricity price increase, %	0.0%	1.5%	3.2%
Retail price increase, %	-0.1%	0.7%	1.7%
Resource costs, $M	158	623	818
GDP costs, $M	na	835	Na
Benefits			
Abatement of greenhouse gas in the SWIS, Mt CO_2e	14	30	42
Investment in renewable energy generation, $M	477	1,054	1,496
High carbon price			
Impacts			
Certificate price, $/certificate	12.0	17.1	17.3
Wholesale electricity price increase, %	-0.4%	1.0%	1.3%
Retail price increase, %	-0.4%	0.5%	0.7%
Resource costs, $M	463	901	1,156
GDP costs, $M	na	296	Na
Benefits			
Abatement of greenhouse gas in the SWIS, Mt CO_2e	14	27	41
Investment in renewable energy generation, $M	688	1,198	1,740

Source: Analysis by MMA and CoPS. The abbreviation "na" denotes not available.

1 INTRODUCTION

In its 2005 election platform, *Labor's Plan for Renewable Energy*, the Western Australian Government committed to develop a renewable energy target for 2020.

In the short to medium term, electricity from renewable energy is likely to be more expensive than fossil fuel based generation. The Government needs to understand the costs a target may impose on the Western Australian economy and key stakeholders, in order to set a realistic target.

The Western Australian Office of Energy has commissioned McLennan Magasanik Associates (MMA), Insight Economics and Monash University's Centre of Policy Studies (CoPS) to undertake an analysis of a 2020 target for renewable energy in the South West Interconnected System, the state's main electricity grid. The analysis will be used to inform decisions on the ultimate target to be obtained and the likely mix of renewable energy generation options for achieving it. Outputs from the analysis will be used to:

- Establish a baseline projection for renewable energy generation in Western Australia.
- Help the Government set a target that is appropriate for the state's circumstances.
- Quantify the potential impacts of a target for energy users and other stakeholders.

This report outlines the modelling approach and assumptions used in the analysis and a discussion of the key results. An optimisation model of the renewable energy generation market is used to determine the least cost combination of renewable energy resources required to meet the 2020 target, taking into account the impacts that higher levels of renewable energy generation will have on the electricity market.

Key results obtained from the analysis include:

- Uptake of renewable energy technologies and investment in renewable energy capacity.
- Impact on wholesale and retail electricity prices by customer class.
- Abatement of greenhouse gas emissions.
- Impact on coal-fired and natural gas fired generation sectors, including existing generators.
- Cost of additional resources used in electricity generation.
- Economic and employment impacts for Western Australia.
- Impacts on industry outputs.

The implications of these results for the electricity market and the wider economy are also discussed.

In this report, the target for renewable energy is denoted as the Renewable Energy Target Western Australia (RETWA) scheme.

Monetary values in this report are in mid 2006 dollar terms, unless otherwise stated. Present values of economic impacts are calculated using a 5.9% discount rate[1].

[1] Equivalent to the nominal value for the ten year bond rate as at January 2007. This was converted into real terms assuming an inflation rate of 2.5%.

2 METHOD AND ASSUMPTIONS

2.1 Structure of scheme

For the purpose of modelling impacts it has been assumed that any renewable energy target scheme would be similar in design to schemes in other jurisdictions. The scheme is assumed to be a mandatory, market based incentive scheme to increase the amount of electricity derived from renewable energy sources in Western Australia. The proposed scheme is consistent in structure with the Commonwealth Mandatory Renewable Energy Target (MRET), the Victorian Renewable Energy Target (VRET) and proposed New South Wales Renewable Energy Target (NRET) schemes.

Elements of the scheme are assumed to be:

- Retailers and large wholesale purchasers of electricity located on the SWIS are required to purchase increasing amounts of power from new renewable energy sources. Liabilities are assumed to be shared between retailers on the SWIS each year, proportional to their electricity sales. Self generators and trade exposed, energy intensive industry located on the SWIS are assumed to be exempted from the scheme.
- Generators create certificates for new renewable energy generation from eligible technologies. The income renewable energy generators receive for their certificates makes them competitive with fossil fuel generators, providing an incentive for them to invest in new capacity. The price in the certificate market increases until there is enough stimulus to bring on sufficient new generation to meet the target. For existing generators, it is assumed that certificates will only be issued for expansion in generation capacity above pre-existing levels.
- Retailers demonstrate compliance by purchasing and surrendering certificates. Certificates are fully tradeable between all market participants. The costs of purchasing certificates incurred by retailers and large wholesale purchasers are assumed to be passed through to electricity consumers.

It is assumed that the mandatory renewable energy target is translated into a fixed quantum of electricity (GWh). The target will represent the difference between renewable energy generation required to meet the Government's renewable energy target for the SWIS in 2020, less that expected under existing policy mechanisms. Furthermore, it is assumed that the mandatory target will be increased gradually from 2010 to its maximum level in 2020.

It has been assumed that liable parties will be able to bank certificates for use in future years. This allows generators to optimise the timing of large-scale plant investment and retailers to better manage their ongoing liability.

It is assumed that certificates used to meet Commonwealth MRET requirements cannot be used to meet requirements under the Western Australian scheme. This is consistent with the approach used in other jurisdictions.

The scheme is assumed to support renewable energy technologies not yet widely deployed in Western Australia. Eligible generation technologies are assumed to be consistent with the MRET and VRET schemes and will include generation from wind, biomass, geothermal, hydro, solar, photovoltaic and wave resources.

New renewable energy generation located anywhere in the State, including in off-grid applications, is assumed to be eligible to earn certificates.

Eligible generators are assumed to be able to create certificates for a period of 15 years from the year they commence generation.

Different target levels have been modelled to compare impacts on the electricity market and the economy. However, all target scenarios use the same generic scheme design.

2.2 Method overview

Examination of the impacts and cost of a renewable energy target requires the use of both bottom-up and top-down economic modelling. This modelling was undertaken jointly by MMA and CoPS:

- MMA modelled the impact of different options on the electricity sector in the south west of Western Australia.
- The outputs of the MMA modelling were fed into CoPS' MMRF model to determine the impact on the broader Australian economy. The output of the MMRF model included the impacts of renewable energy targets on greenhouse gas abatement, energy demand, employment levels, investment, GDP and inter–industry effects.

The first stage of the modelling was to develop the model inputs and assumptions in conjunction with the Office of Energy. MMA used an extensive database on supply costs for electricity generation and of future costs of new technologies for electricity generation.

Policy settings affecting the electricity market and renewable energy markets were also formulated. The major assumptions regarding policy settings include:

- RETWA is enforced, commencing in 2008 and liabilities commencing from 2010, with the final certificates issued in 2035. The assumed design of the RETWA scheme is similar to schemes in other jurisdictions, and presumes there is a linear ramp-up of interim targets to the final target in 2020. It is also assumed that only new renewable energy generators commencing operation from 2008 onwards are eligible to create certificates under RETWA. Renewable energy generators can either create a Renewable Energy Certificate Western Australia (RECWA) or a certificate under the MRET scheme, but not both for each unit of eligible generation.

- It is assumed that the MRET scheme continues to operate as planned. There is no increase in the target above the 9,500 GWh level and the scheme expires at the end of 2020. The RETWA scheme will impact on MRET because renewable energy generators in Western Australia will be able to choose to earn certificates under MRET or RETWA.

- The VRET scheme, which commenced in 2007, is modelled to achieve an ultimate target for new renewable energy generation in Victoria of 3,274 GWh in 2016. The scheme is assumed to continue until 2030. The NRET scheme is also assumed to commence in 2008, ramping up to a target of 7,250 GWh of new renewable energy generation in 2020. The scheme is assumed to expire in 2035. Similar rules on eligibility apply to both schemes. These two schemes indirectly impact on choices for renewable energy generation in Western Australia by impacting on choice of plant for MRET. If new renewable energy plant in the NEM divert to either of these schemes, this may allow new renewable energy plant from Western Australia to fill any resulting deficit under the MRET scheme and therefore not be available for the RETWA scheme.

It was assumed that an emission trading scheme was in place covering the electricity generation sector, in line with Western Australian government policy. Emission trading was modelled as an assumed price for carbon emissions, where the prices are associated with notional national emission abatement targets. Prices for carbon emissions were based on projections published by the National Emission Trading Taskforce (see Section 2.3.2).

The second stage of the study involved detailed modelling of the electricity markets over the time frame of the study using MMA's bottom-up model of the SWIS. This model simulates the Western Australian Electricity Market (WEM) to determine:

- Dispatch of generating plant and electricity supply costs arising from this dispatch for each year.

- Timing and type of new investments in electricity generation and energy efficiency projects for each region.

- Impact of schemes such as MRET and the proposed RETWA on dispatch and electricity prices.

Outputs from the simulation model are then input into the MMRF model of the Australian economy, which was the third stage of the modelling process. The MMRF model estimates the impacts of the RETWA on economic growth, employment and industry output.

The RETWA scheme affects electricity prices and, hence, influences electricity demand. However, the bottom-up electricity market modelling presumes that the electricity demand is fixed. Where the demand impact was significant, a process of iteration between the bottom-up model and the MMRF model was undertaken to ensure

consistency of results across the models. Energy demand from the MMRF model, after simulating the impacts of the RETWA based on the outputs of the bottom-up modelling, was fed back into the bottom-up models, and the second and third stages of the modelling process were repeated.

2.3 Modelling impacts on the electricity market

Any method to project the impacts of RETWA requires modelling of the electricity markets in Western Australia. The method needs to account for the economic relationship between the electricity and renewable energy markets, the competitive structure of the WEM and the market for renewable energy certificates. Future REC/RECWA prices are dependent on wholesale electricity prices and the cost of renewable energy generation. In turn, the entry into the SWIS of additional renewable energy generation will impact on wholesale electricity prices.

Two models were developed to project prices of electricity and RECWAs:

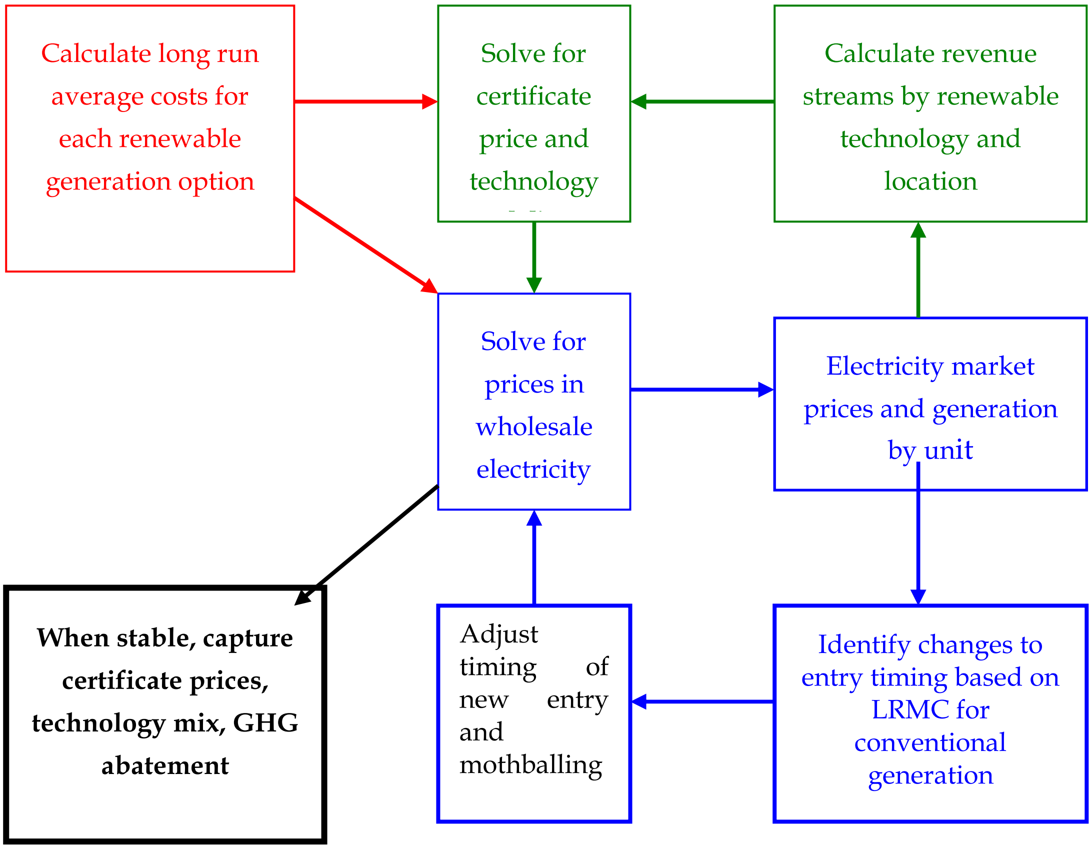
- Renewable Energy Market Model Australia (REMMA[2]), which simultaneously solves for the adoption of renewable energy generation and the renewable energy certificate price for the range of schemes currently in place or about to be introduced in Australia. These include the MRET, VRET and NRET schemes. RETWA was added on to the model to allow for interaction between the MRET and RETWA schemes.

- MMA's STRATEGIST Model of the South West Interconnected System (SWIS), which is a model that simulates the dispatch of electricity plant in the SWIS to meet demand forecasts based on relative cost of generation as determined by generator bids. The wholesale electricity market simulation model depicts each of the generators operating in the electricity market and demand on an hourly basis.

An overview of the modelling process is shown in Figure 2-1. An iterative approach is used to simultaneously solve for the timing and selection of new renewable energy generation plant, since the new generation impacts on wholesale market prices in the WEM which in turn affects project viability and the RECWA price. Each stage of the modelling approach is repeated until stable wholesale market prices and REC/RECWA prices are achieved.

[2] REMMA is a propriety to MMA. The version used in the analysis was REMMA V13.3.

Figure 2-1: Overview of method for projecting certificate prices and technology mix



Note: LRMC = long run marginal cost of electricity generation. It is a measure of the cost of new plant per unit of electricity produced by the plant. It is calculated as the present value of all costs of a new plant over its assumed life, divided by the present value of the output over its life, where the discount rate used is equal to the weighted average cost of capital.

2.3.1 Renewable energy project database

MMA has a detailed database of renewable energy projects in Australia covering existing, committed and proposed projects to determine the likely cost and availability of renewable energy generation. The database includes all potential projects that have been announced, regardless of whether all approvals have been received.

The database includes estimates of capital costs, likely reductions in capital costs over time, operating and fuel costs, connection costs, and other variable costs for each project. Data on these variables were sourced from:

- Published announcements of proposed projects. Usually these are in the form of media announcements containing information on the site, capacity of the project, generation level (or a projected capacity factor) and total capital expenditure.
- Annual reports of generating companies, which provide information on fuel use (in biomass projects) and generation levels achieved. Details on new projects may also be provided.

- Business Council for Sustainable Energy's monthly reports, which provide capacity, generation and cost details for newly commissioned projects.
- WA Office of Energy, which provided information on some proposed renewable energy generation projects for the SWIS.
- Office of Renewable Energy Regulator's registry database, which contains details of the level of generation from power plant eligible to earn certificates under the Mandatory Renewable Energy Target.
- International data on capital cost trends from the IEA and World Resources Institute.
- Operating cost data based on published data on manning levels at renewable energy power stations.

Renewable energy plants in operation or under construction in Western Australia are likely to be able to provide around 816 GWh of electricity generation a year. A further 2,800 GWh of projects are in various stages of planning and development.

Additional projects are expected to emerge in response to a mandatory target scheme and a number of representative projects have been added to the model database. The generic projects amount to 4,500 GWh a year of additional generation, with approximately half coming from wind projects and half biomass projects based on crop waste and, to a lesser extent, Mallee tree coppicing.

Assumptions on the cost of these projects are as follows:

- Each project was considered of similar size for the technology type. There are six biomass projects, with capacities of 20 MW (four projects) and 50 MW (two projects representing potential large scale wood waste projects). Wind projects amounted to 1,600 MW, with cost data applying to 100 MW sized wind farms. The wind capacity was divided evenly between locations north and south of Perth.
- Costs were calculated so that the long run marginal costs of these projects were higher than costs for known projects for the technology class, under the presumption that currently identified projects and sites are the most prospective for development. This means that these projects would not be chosen ahead of known projects for the technology class. Average generation costs for generic wind projects were increased by reducing capacity factors (from 30% to 27%[3]), mimicking the fact that new wind farms will be located on sites with lower wind regimes. Transmission and ancillary service costs were also assumed to be higher than for known projects. This reflects the fact that new wind farms are likely to be located further from major load centres as more capacity is installed and that system stability costs will also rise with higher levels of wind capacity. Costs for new biomass plants (assumed to be utilising wood waste) were increased by increasing fuel costs (ranging from $2.00/GJ maximum of

[3] These capacity factor assumptions are MMA estimates and are lower than the capacity factors achieved at installed wind farms in Western Australia.

$2.70/GJ compared with a range of $0.42/GJ to $2.00/GJ for known wood waste projects), reflecting the fact that collection, transport and handling costs for biomass fuels are likely to increase with increasing capacity.

Table 2-1 shows the range of costs for new renewable energy generation projects.

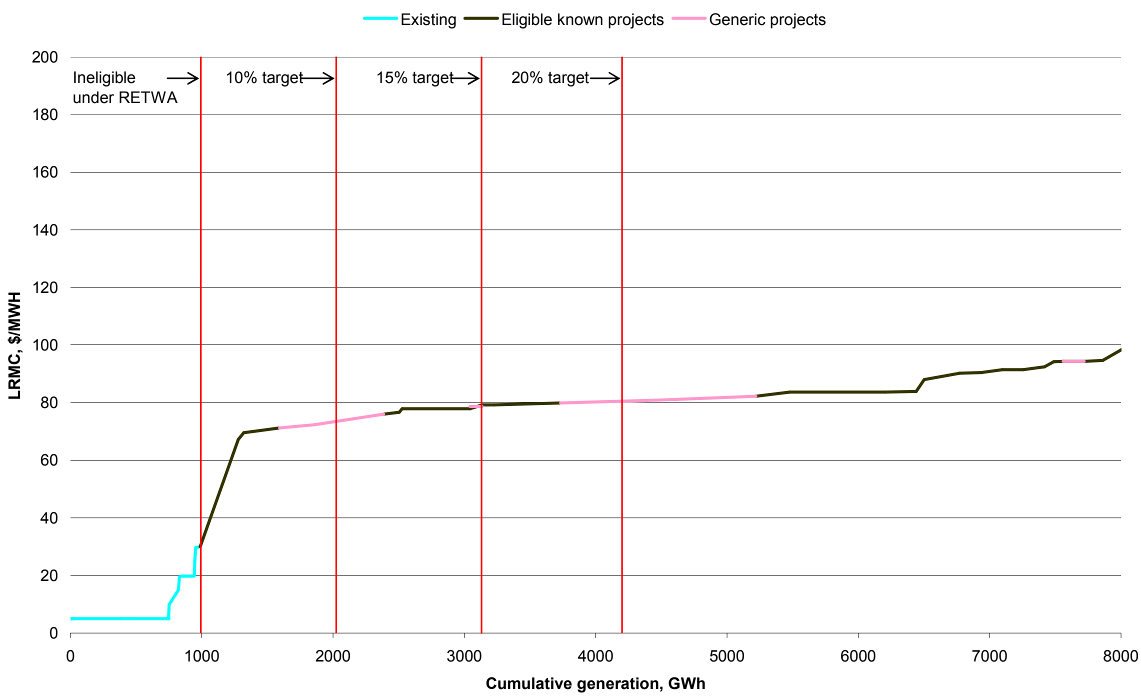
Table 2-1: Cost of new renewable energy generation in WA, $/MWh, 2006

Renewable energy generation type	Minimum	Maximum
Solar/PV	120	343
Wind	85	180
Biomass	87	219

Source: MMA renewable energy database for Australia.

The long run marginal cost of renewable energy generation as a function of cumulative generation is shown in Figure 2-2.

Figure 2-2: Indicative long run marginal cost curve for renewable energy generation in Western Australia in 2020



Note: Indicative cost curve for renewable energy generation projects in Western Australia. The long run marginal costs is derived by dividing the present value of total costs by the present value of expected generation over the life of the project, where the present value are calculated using a real weighted average cost of capital of between 9.0% to 10.5%. Other factors (e.g. size, intermittency, electricity prices received and other income) will also influence the order in which projects actually proceed in the modelling.

2.3.2 REMMA model

The REMMA model 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 was determined from the

difference between the long run marginal cost of generation of the marginal renewable energy 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 is directly dependent on the cost of renewable electricity generation. The renewable energy certificate will equal 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 energy option dispatched to meet each of the interim targets sets the market clearing price and the certificate price. Prices for RECWAs in the RETWA will be higher than the REC price projections in the business-as-usual MRET scenario, because RETWA eligible generation will be over and above the level induced by MRET.

The model is a long-term contract model and presumes complete knowledge about future wholesale electricity prices and generation levels in the electricity market, as well as future certificate prices in the RETWA market. In the real world, uncertainty about future market prices could lead to RECWA price dynamics that differ from the projections made in this study. For example, spot prices for RECs in the MRET scheme were probably too high initially, and collapsed in 2006 as the consequences of an initial flurry of investment activity became apparent to the market.

The modelling approach is grounded in the expected underlying costs and availability of renewable energy generation in Western Australia and, on this basis, this study provides a reasonable expectation of the economic impacts of the scheme.

From time to time, there will be variations in RECWA prices around long-term mean values, due to short-term factors such as, higher or lower than expected levels of generation from renewable energy generators. Banking creates an additional demand for certificates in the early years of the scheme, by allowing parties to purchase certificates in excess of their immediate liabilities and use them in future years. With this capacity to manage forward risk, the variation in prices could be minimal.

REMMA is designed to select the combination of renewable energy generators to meet targets for renewable energy generation under the various market based support programs. The market simultaneously solves for the cost of generation, prices for market based instruments and choice of renewable energy technology by type and location under the various market based instruments. The current version simultaneously solves for the federal government's MRET target, the VRET target and the proposed NRET target[4]. The model has been modified to include the proposed targets under RETWA. Essentially, the model allows renewable energy generators to choose which market instrument they wish to trade under, on the assumption that a renewable energy generator can only earn revenue from one instrument. For example, a renewable energy generator in Western

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[4] The model can also solve for how much renewable generation would enter the market under an emission trading scheme. This is handled within the model by inputing the higher electricity prices received with carbon prices. The resulting higher electricity prices would mean a lower certificate price is required for the RETWA targets to be met.

Australia can only earn revenue (apart from sales of electricity into the WEM), from either the RETWA scheme or the federal MRET scheme.

Because the renewable energy model considers the interactions of each generating unit, it can also be used to predict the technology mix. The combination of plant in each year is determined using an integer programming algorithm that selects plant on the basis of least cost[5]. Plant cost is defined as the annualised cost of generation, including system charges and connection costs, minus any revenue from sales to the wholesale market or from other sources[6].

Certificate prices are forecast for the most likely outcome in terms of electricity price, availability of renewable energy resources and generation costs. In this study, the impacts of other factors that may affect certificate prices have not been modelled. Such factors include trading strategies to support wholesale market prices above marginal cost and variations about expected generation levels of intermittent generation.

The forecast of RECWA prices is based on the assumption that the price of the RECWA will be the difference between the levelised cost[7] of the marginal renewable energy generator and the price of electricity achieved for that generation over the life of the project. The basic tenet of the RETWA scheme is that the RECWA price provides the revenue, in addition to the electricity price, that is required to make the last renewable energy generator needed to meet the RECWA target viable.

In a simple system, the RECWA price would be determined by identifying the marginal generator and performing a simple subtraction of these two values. However, the model also incorporates the following features:

- Introduction of new renewable energy generators affects the investment cycle in the conventional generation sector and, hence, wholesale electricity market prices. This in turn affects the additional revenue required to make renewable energy generators viable. An iterative approach is used to simultaneously solve for wholesale electricity market and RECWA market price projections.

- Under RETWA as modelled, more certificates can be created in a year than required to meet the target to be banked and surrendered at a later date (similar to what is allowed under the MRET, VRET and NRET schemes). Banking allows investment in comparatively large but cost-effective electricity generation units to be reconciled with incremental increases in interim targets and liabilities. The banking facility allows the supply of renewable energy generation to be higher or lower than the interim target in

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5 The price is determined simultaneously as the marginal cost of the last plant selected to meet the demand for RECs and RECWAs in any year.

6 Other revenue can include levies received from local councils for avoiding landfill charges, payments for avoiding network upgrades and revenue from sales of by-products (such as cleaned recyclable materials from some waste to energy projects).

7 Levelised cost is the average per MWh cost of generation required to be earnt over the output from a project over its life, where the costs include a commercial rate of return. Mathematically, it is equal to the present value of total costs (including capital, operating and fuel costs), divided by the present value of the projected output of the plant over its life. The present values are calculated using the weighted average cost of capital for a typical project.

any given year, while ensuring the total amount of electricity generated over the life of the scheme is the same.

- Because capital costs are sunk, installed and committed generators are assumed to be operating with just the marginal cost of generation considered in the modelling. These marginal costs are lower than the long run marginal costs for new units, thus committed plant are not likely to set the certificate price in any year.
- Resource and other constraints limit the uptake of renewable energy generation. This is reflected in the model in two ways, depending on the type of constraint. Physical limits to production are input into the model as a limit on the amount of new generation that can enter the market in any year. Resource constraints, for example fuel availability, are modelled by increasing the marginal cost of the resource.

In the Western Australian market, physical constraints include limits on the amount of intermittent generation in the market. The main constraints are modelled as follows:

- As the proportion of intermittent generation increases, a higher level of reserve capacity will be required. This increases the total cost of generation for the market. A low availability factor is imposed on wind generation to enable reserve capacity to be determined by the model. This impact is felt by the intermittent plant in that the wholesale market price received is reduced by the reduction in capacity payment they receive for having a lower level of firm supply. Intermittent plant only get a capacity payment for their firm capacity, which in the case of wind generation is assumed to be 35% to 40% of the nominal capacity of existing plant, 30% to 35% of announced or proposed new plant and 27% to 30% for generic new plant[8].
- System stability constraints due to the potential fluctuations in wind generation levels over time. To account for the additional cost of equipment to improve system stability, an ancillary service charge of between $5/kW to $10/kW is imposed on all wind generation capacity[9].
- The probability that wind generation would earn negative revenue on the spot market if there is an excess amount of wind generation in off-peak periods. The model forces a certain proportion of the steam units to stay on-line (at close to minimum capacity levels) during off-peak to meet spinning reserve requirements. Cogeneration plants are also assumed to stay on-line overnight, due to their need to meet the host's steam requirements. The model accounts for the fact that excess wind generation may need to be dumped at negative prices in off peak periods, which reduces the expected return to intermittent generators.

The optimisation requires that the interim targets are met in each year (by current generation and banked certificates). Banking is determined by calculation of the present

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8 The IMO rules state that firm capacity for wind generation for the purposes of calculating capacity credits is to be set at their average capacity of operation.

9 MMA estimates based on data provided by the wind industry.

value to the market if a plant is introduced earlier. The model chooses the timing of entry of plant and hence RECWA prices, such that the cumulative target at the end of the study period is met at least cost.

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

The REMMA model determines the future price path of RECWAs in the following steps:

- The costs of a range of renewable energy generation options have been determined as the long run marginal cost of generation over a 15 year investment horizon. The 15 year investment horizon is used as a typical period over which contracted energy sales would be required to enable financing of a project[10]. The weighted average cost of capital estimate is based on existing market rates for generation investments. Where data has been published, the costs include the costs of connection to the grid. This can form a significant proportion of the capital costs of a project, particularly where no local transmission wires are available. Connection costs data are based on published data of connection costs for existing projects. Connection costs are assumed to be at least 5% higher for new projects.

- The projected spot market price in the WEM is used to derive the price that a generator could obtain for its power generated. Wholesale electricity prices are determined on an hourly basis for each week of the study period. Average hourly prices are used to determine the weighted average prices the generator would earn over its level of generation under bilateral contracts, the STEM and from capacity payments.

- Potential revenues from wholesale market transactions and other sources for each project are levelised for the life of the project. Wholesale electricity prices received by the renewable energy projects are weighted according to the generation profile of the renewable energy technology. The levelised revenue is then subtracted from the corresponding renewable energy project long run marginal cost to derive the net costs required to be met through sales of RECWAs.

- For each selected new project, the long run marginal cost of generation is discounted with the electricity sales income, and revenues from any other programs (e.g. steam sales). The discounted cash flow compared with the long run marginal cost indicates whether a given RECWA price path will justify the construction of a project.

- The plant installed in each year is determined by the economic viability subject to the RECWA price path, and also subject to resource constraints, RECWA creation and surrender constraints. The resource constraints are indicated by capacity available from each source in each year.

10 The 15 year period is also consistent with the length of time a generator can earn certiciates under the VRET scheme and is consistent with the recommendations of the Tambling Inquiry into the MRET scheme.

- The resulting MW installed and generation levels are then entered into the wholesale electricity market model to determine the resultant market price changes, which in turn impact the certificate prices.
- The resulting market price paths are iteratively input into the initial step above, until stable market price paths, RECWA price paths and installed renewable energy generation options are achieved.

Technology mix and investment levels are an output of the modelling process and are determined by the optimal (cost-minimising) investment path.

Most renewable energy plant already operating or committed are assumed to remain in operation for the duration of MRET/RETWA, regardless of prices received for certificates and electricity. This assumption is based on the fact that most of these generators are underwritten by long-term contracts and the fact that their capital costs are sunk. Four older landfill gas plants are assumed to progressively retire from 2007 to 2012, as their gas supplies run out. Recently installed landfill gas plants are assumed to have a life of twelve years, and hence will retire towards 2020.

Planned projects are assumed to enter the market when demand dictates. Projects are selected on the basis of ascending long run marginal costs, with the amount selected in any one year determined by the demand for certificates (which is based on the target amount of certificates required to be redeemed, plus the demand for certificates to be banked to meet future liabilities). The next lowest cost generation operation will be installed in a given period if the cumulative interim target has not been reached.

Prices and generation chosen under RETWA are also impacted by what occurs in other electricity markets in Australia via the MRET scheme. Because renewable energy generators in Western Australia are also eligible to earn RECs under the MRET scheme, they can choose either to participate in MRET or RETWA. The interactions between the MRET market (and electricity prices in the NEM) and the proposed RETWA market were explicitly modelled in the REMMA model.

2.3.3 Electricity market model

MMA's electricity market model enables the calculation of average wholesale market prices in the WEM arising from the dispatch of generating plant to meet electricity demand in each trading interval. The modelling approach assumed competitive market conditions, with no strategic bidding behaviour, and perfect foresight. Under these conditions, prices in the contract and STEM markets would be expected to converge. In STRATEGIST, the contract and STEM markets are modelled as a single, competitive market for electricity generation. In this market, generators bid at their short run marginal cost of generation, and retailers pay a market clearing price.

A commercial rate of return is built into the cost of new generation capacity, so new entrants enter the market only if it is profitable for them to do so.

The modelling algorithm incorporates:

- Chronological hourly loads representing a typical week in each month of the year. The hourly load for the typical week is consistent with the hourly pattern of demand and the load duration curve over the month.
- Short run marginal cost bidding for thermal plant.
- Scheduled and forced outage characteristics of thermal plant.
- Demand-side bidding and interruptible loads as a dispatchable resource.

Each power plant is considered separately in the model. The plants are divided into generating units, with each unit defined by minimum and maximum operating capacity, heat rates, planned and unplanned outages, fuel costs and operating and maintenance costs.

Electricity prices are determined by the bid of the last plant dispatched. Prices and costs forecast in this manner represent wholesale electricity prices including network losses, but do not include network charges or retail mark-ups.

For each period, the model then chooses generation from plants in order from the cheapest to the most expensive, until the demand for that period is met. Additional capacity, such as refurbishments or expansions, are handled in this same manner and added to the available generation to meet demand.

Intermittent generation can increase ancillary service, system reliability and transmission costs. These are reflected in the modelling in this study as follows:

- The model ensures that an energy not served constraint is met at all times. The maximum level of energy not served allowed in the model is 0.002% of total energy demand, which is equivalent to one measure of reliability used by the WA Independent Market Operator (IMO). The model accounts for wind's intermittency in its selection of new capacity, because plant selection is subject to minimising the overall cost of meeting this reliability constraint[11].
- Ancillary service costs are simply modelled as an additional cost for wind generation. A fee of between \$5/kW to \$10/kW is added to wind generators to cover additional ancillary service costs.
- Transmission costs are included as connection fees. With the planned upgrade of the transmission system north of Perth (Eneabba to Geraldton), it is assumed there is adequate transmission capacity to handle any additional wind generation used to meet the targets modelled in this study. Thus, it is assumed that there are no costs associated with major upgrades to the transmission network.

[11] Wind generation is modelled with a probability of being out of action during any trading interval of between 27% to 40%.

2.3.4 MMRF model

MMRF is a computable general equilibrium model of the Australian economy. The model is designed to estimate the impacts of policy shocks on the state and national economies. Impacts are measured for:

- Gross Domestic and Gross State Product (a measure of national income or the value added from economic activity in Australia).
- Private consumption and investment.
- Employment and real wages.
- Value added by ASIC sectors.
- Regional income.

MMRF divides Australia into the six states and two territories. There are five types of agents in the model: industries, capital creators, households, governments and foreigners. The number of industries is limited by computational constraints. Currently, MMRF identifies 54 products produced by 49 industrial sectors. For each sector in each region, there is an associated capital creator. The sectors each produce a single commodity and the capital creators each produce units of capital that are specific to the associated sector. Each region has a single household and a regional government. There is also a federal government. Finally, there are foreigners, whose behaviour is summarised by export demand curves for the products of each region and by supply curves for international imports to each region.

MMRF determines regional supplies and demands of commodities through optimising behaviour of agents in competitive markets. Optimising behaviour also determines industry demands for labour and capital. Labour supply at the national level is determined by demographic factors, while national capital supply responds to rates of return. Labour and capital can cross regional borders, so that each regions stock of productive resources reflects regional employment opportunities and relative rates of return.

The specifications of supply and demand behaviour co-ordinated through market clearing equations comprise the general equilibrium core of the model.

MMRF contains a number of factors that enhance its capability for energy policy analysis. These include:

- An energy and gas emission accounting module, which accounts explicitly for each of the 49 industries/54 products and eight regions recognised in the model.
- Equations that allow for inter-fuel substitution in electricity generation by region.
- A multi-product specification for oil refineries.
- A detailed treatment of renewable energy generation.

MMRF tracks (primary and final) energy usage and emissions of greenhouse gases at a detailed level. It breaks down energy-usage/emissions according to:

- Using/emitting agents (49 industries and residential).
- Using/emitting state or territory (8).
- Using/emitting activity (10).

Most of the using/emitting activities are the burning of fuels (black coal, natural gas, brown coal or petroleum products). A residual category, named Activity, covers emissions such as fugitives and agricultural emissions not arising from fuel burning.

Energy usage is measured in units of PJ. Emissions are measured in terms of carbon dioxide equivalents, CO_2e. The base usage and emissions matrices are calibrated to be consistent with observed data between 1990 and 2001, using information from the 2001 NGGI and ABARE (2003).

Carbon pricing is handled in the same way as in the electricity market models. Prices for carbon emissions are simply input as an additional cost for each tonne of carbon dioxide equivalent released during the production process.

Inter-fuel substitution in electricity generation is handled using the "technology bundle" approach. Nine power-generating industries are distinguished based on the type of fuel or renewable energy resource used (in Western Australia this is confined to black coal, gas, oil products, hydro, biomass, biogas, solar and wind). There is also an end-use supplier (Electricity Supply). The electricity generated in each state/territory flows directly to the local end-use supplier, which then distributes electricity to local and interstate users. The end-use supplier can substitute between the five technologies in response to changes in their production costs. For example, the electricity supply industry in Western Australia might reduce the amount of power sourced from coal-using generators and increase the amount sourced from gas-fired plants.

For other energy-intensive commodities used in industry, MMRF allows for substitution possibilities by including a weak form of input-substitution specification.

MMRF makes allowances for multi-product industries and multi-industry products. In the current version of the model, this allows the petroleum refinery industry to produce six separate products:

- Petroleum for automotive use only.
- Petroleum for aviation use only, commonly called AvGas.
- Aviation turbine fuel.
- Diesel for automotive use.
- LPG for automotive use.
- Other petroleum products, which include kerosene, heating oil and fuel oil.

Each product has a distinct sales pattern.

A detailed treatment of renewable energy technologies has been incorporated into the model. Five separate industries each producing electricity from a specific renewable energy source are modelled. The five sources are hydro, biomass, biogas, solar and wind. In broad terms, the production technologies for biomass and biogas generation are more labour intensive than for solar and wind generation, and less intensive in the usage of machinery and equipment. The production technology for hydro generation is about halfway between each of these extremes.

Labour markets

The deviation in the consumers real wage rate (i.e., the nominal wage rate deflated by the CPI) from its base case forecast level in the RETWA scenarios, is assumed to increase in proportion to the deviation in employment (hours) from its base case level. The coefficient of proportionality is chosen so that the national employment effects of the RETWA program in any year are largely eliminated. In other words, the benefits of the scheme are almost entirely realised in the national labour market as a change in the real wage rate, rather than as a change in employment. This labour market assumption reflects the idea that in the long-run, national employment is determined by demographic factors (birth and death rates, the level of international migration), which are largely unaffected by the RETWA scheme. It is also consistent with conventional macro-economic modelling in which the Non-Accelerating Inflation Rate of Unemployment is exogenous.

Although, in the simulations the RETWA scheme does not affect Australia-wide employment in the long-run, it does affect the regional distribution of employment. Labour is assumed to move between state economies so as to maintain inter-state wage and unemployment rate differentials at their base case levels. Accordingly, regions which are favourably affected by the RETWA program will experience increased employment and population at the expense of regions that are less favourably affected.

Public expenditure, taxes and government budget balances

The shocks associated with the new RETWA scheme are assumed to make no difference to the path of the federal government's budget balance. The budget is fixed at its base case level by endogenous changes in income tax rates.

Private consumption and investment

Consumption expenditure of the regional household moves in line with changes in household disposable income (HDI). HDI is the sum of factor payments (wages and dividends) to Australian residents and government transfer payments (unemployment and other personal benefit payments), less direct income tax. In calculating the change in HDI due to the RETWA scheme, account is taken of the income directly generated by the scheme, the income indirectly generated via input/output linkages and induced income effects, and endogenous changes in income tax rates.

Investment in each regional industry in each year is assumed to deviate from the base case in line with the deviation expected rate of return on the industry's capital stock. Investors

are assumed to be myopic, implying that expected rates of return move with contemporaneously observed rates of return.

Rates of return on capital

In deviation simulations, MMRF allows for short-run divergences in rates of return on industry capital stocks from their levels in the base case forecasts. Such divergences cause divergences in investment, and hence capital stocks. The divergences in capital stocks gradually erode the divergences in rates of return, so that in the long-run rates of return on capital over all regional industries return to their base case levels.

Production technologies

MMRF contains many types of technical change variables. In the deviation simulation, all technology variables are assumed to have the same values as in the base case simulation.

2.4 Assumptions

2.4.1 General

A number of high level assumptions are employed in the modelling of all indicative policy scenarios.

The study period is 2008 to 2035.

IMO's median energy and peak demand forecasts are used in all scenarios, except where electricity price impacts lead to a response in demand. The demand forecasts are extrapolated beyond 2015, using implied trend growth for the period from 2010 to 2015.

New capacity is installed to meet the target reserve margin for the SWIS.

Availability, heat rates and capacity factors of all plants in the SWIS (including non-renewable energy generators) are based on historical trends and other published data.

Fuel prices for gas generators for new gas supplies (i.e. above existing contract commitments) are assumed to be priced at $4.60/GJ delivered into Perth in 2006. This price remains constant in real terms throughout the study period. Coal prices are assumed to be $40/t in 2006, which is assumed to remain constant in real terms through the study period.

Non-fuel operating costs are estimated based on published data and bid information.

Capital costs for thermal generation options are based on published data and industry knowledge.

Real capital costs for all technologies, renewable energy and conventional, are assumed to fall over time. A "capital cost reduction factor" is included for each technology in the analysis to model this effect, ranging from around 2% per annum for wind generation technologies from 2010 and 1% per annum for biomass technologies from 2010. Details on the capital cost reductions assumed are contained in Appendix B.

Future transmission and distribution prices are estimated from historical trends in prices and recent regulatory decisions on allowable movements in prices (under the CPI-X provisions).

Greenhouse gas emissions per generating unit are estimated based on National Greenhouse Gas Inventory (NGGI) data on emission intensity per unit of fuel used.

Any changes in wholesale electricity prices are assumed to flow through to retail prices (including any decrease in wholesale electricity prices). Price increases are therefore borne by the broad customer base.

2.4.2 Policy related assumptions

The renewable energy target is calculated on the basis of the electricity demand load on the SWIS. The target is based on metered customer demand as at the transmission/distribution connection nodes. The marginal loss factor used to convert sent-out demand to metered demand at the distribution/transmission junction is 1.05, based on information published in Western Power's annual reports.

Generation required under the mandatory target scheme is calculated as the percentage target multiplied by forecast grid supplied electricity demand, and then deducting generation levels from existing renewable energy plant. For the purposes of calculating the target, the grid supplied demand does not include behind the fence generation.

A linear approach is used to set the interim targets, starting at 6% in 2010.

Penalties are not enforced in this analysis[12].

The scheme commencement date is 1 January 2008, with liabilities starting from 2010. It is assumed that only new generators or capacity expansions at existing generators commencing operation from 1 January 2008 are eligible to earn certificates under RETWA.

Load demand from energy-intensive and trade-exposed industries (alumina refining, mineral ores, iron and steel and non metallic mineral processing) is exempt from being liable under the scheme. This means that these loads do not attract liability for purchasing certificates under RETWA. To ensure the target is met, liabilities for exempt loads are spread across the liable load[13].

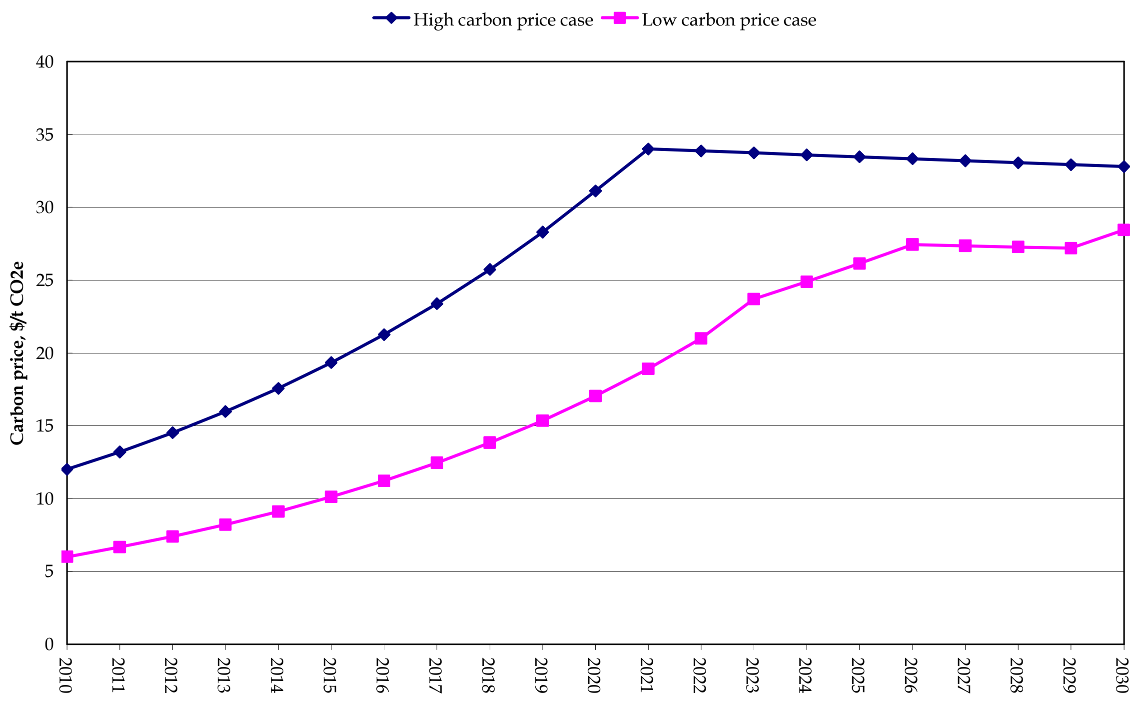
A National Emission Trading Scheme commences operation in 2010. Modelling of emission trading was not undertaken. Rather, two price paths reflecting the low and high range of permit prices were input into the model as a carbon penalty. The carbon prices are based on the low and high carbon price projections undertaken recently by MMA for the National Emissions Trading Taskforce. The low price accords with the prices for Scenario 1a (emission trading to a 179 Mt CO_2e target for emissions from electricity

12 Penalties will be set on the basis of risk management in the scheme design phase.
13 Energy consumption by exempt load calculated using data provided by WA SEDO.

generation in 2030 with a complementary energy efficiency policy) and Scenario 2 (emission trading to a 150 Mt CO_2e target for emissions from electricity generation in 2030). Deeper cuts than modelled under these scenarios will increase the price of carbon. The carbon prices are shown in the following chart.

Carbon prices are incorporated in the model as another variable cost. Each plant has an assumed emission intensity. The carbon price is added to the generation cost for each tonne of carbon emitted per unit of electricity generated by a plant. Because this adds to variable cost, the addition of carbon prices can change the order of dispatch of generating plant.

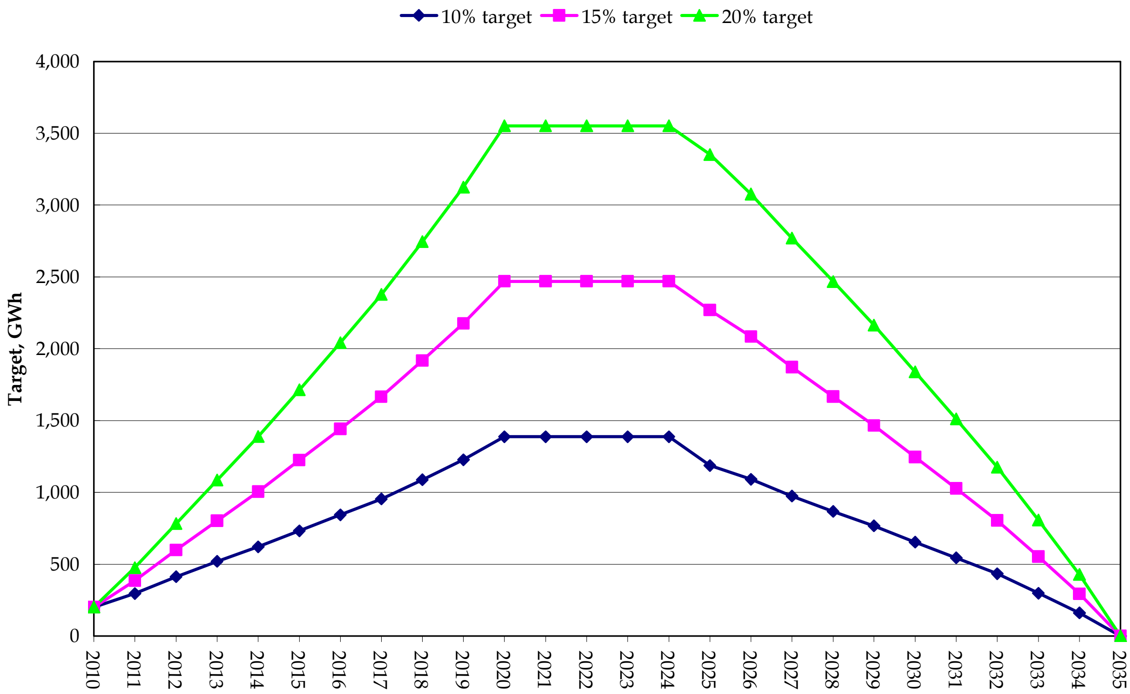
Figure 2-3: Carbon price assumptions



2.5 Scenarios

The focus of analysis is on the cost and impacts of different renewable energy target levels for 2020. Consequently, all scenarios presume the same basic scheme design (see Section 2.1), but differ in their target levels for renewable energy generation and the carbon prices paid. Analysis of three prescribed target levels was undertaken: 10%, 15%, and 20% of total generation by 2020. By 2020, the additional renewable energy generation required is around 1,094 GWh for a 10% target, 2,177 GWh for a 15% target and 3,260 GWh for a 20% target.

Figure 2-4: Renewable energy targets



Different price paths for carbon were modelled to allow for uncertainty in likely price paths for carbon.

Eight scenarios were modelled in all, reflecting the four renewable energy targets in 2020 (including no prescribed target) and two carbon price paths. The targets and carbon prices for each scenario are as follows:

- *Scenario 1*: Reference (or business-as-usual) scenario with low carbon price. No prescribed target for 2020.
- *Scenario 2*: Reference (or business-as-usual) scenario with high carbon price. As with Scenario 1, except with a high carbon price imposed on electricity generation.
- *Scenario 3*: 10% renewable energy target in 2020 and low carbon price. The interim targets increase linearly from 6% in 2010 to 10% in 2020.
- *Scenario 4*: 10% renewable energy target in 2020 and high carbon price. As with Scenario 3, except with a high carbon price imposed on electricity generation.
- *Scenario 5*: 15% renewable energy target in 2020 and low carbon price. The interim targets increase linearly from 6% in 2010 to 15% in 2020.
- *Scenario 6*: 15% renewable energy target in 2020 and high carbon price. As with Scenario 5, except with a high carbon price imposed on electricity generation.
- *Scenario 7*: 20% renewable energy target in 2020 and low carbon price. The interim targets increase linearly from 6% in 2010 to 20% in 2020.

- *Scenario 8*: 20% renewable energy target in 2020 and high carbon price. As with Scenario 7, except with a high carbon price imposed on electricity generation.

The government has an existing renewable energy target for the SWIS of 6% by 2010. This is the starting point for the trajectory of interim targets leading up to the ultimate target in 2020 (see Table 2-2).

The 15 per cent target was analysed using the MMRF-Green model, in order to understand the implications of a renewable energy target for the broader economy. The macro-economic analysis was undertaken for all carbon pricing scenarios.

Table 2-2: Renewable energy targets

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Energy demand, sent out basis, GWh	18,682	18,998	19,417	19,784	20,138	20,605	20,995	21,362	21,755	22,149	22,745
Energy demand, distribution connection point, GWh	17,792	18,093	18,492	18,841	19,178	19,623	19,994	20,344	20,719	21,093	21,662
Renewable energy target 10%, %	6.0%	6.4%	6.8%	7.2%	7.6%	8.0%	8.4%	8.8%	9.2%	9.6%	10.0%
Renewable energy target 15%, %	6.0%	6.9%	7.8%	8.7%	9.6%	10.5%	11.4%	12.3%	13.2%	14.1%	15.0%
Renewable energy target 20%, %	6.0%	7.4%	8.8%	10.2%	11.6%	13.0%	14.4%	15.8%	17.2%	18.6%	20.0%
Renewable energy target 10%, GWh	1,068	1,158	1,257	1,357	1,458	1,570	1,680	1,790	1,906	2,025	2,166
Renewable energy target 15%, GWh	1,068	1,248	1,442	1,639	1,841	2,060	2,279	2,502	2,735	2,974	3,249
Renewable energy target 20%, GWh	1,068	1,339	1,627	1,922	2,225	2,551	2,879	3,214	3,564	3,923	4,332
Renewable energy generation from existing capacity, GWh	867	863	845	837	837	837	837	837	818	799	780
Additional required - 10%, GWh	200	295	412	520	620	733	842	953	1,088	1,226	1,386
Additional required - 15%, GWh	200	385	597	802	1,004	1,223	1,442	1,665	1,917	2,175	2,469
Additional required - 20%, GWh	200	476	782	1,085	1,388	1,714	2,042	2,377	2,746	3,124	3,552

Note: Energy demand includes embedded generation to industrial loads. These have been netted out to the extent that they are not liable under RETWA. All amounts other than the top row are on a consumption (and hence liabilities) basis, so transmission losses estimated at 5 per cent have been netted out. To calculate renewable energy targets on a sent out basis, there is a need to factor the transmission losses back in. Calculated yearly liabilities, in GWh, are net of projected growth in Green Power.
Source: MMA analysis using data from the IMO and Western Power's annual reports

3 ELECTRICITY MARKET IMPACTS

Setting a renewable energy target will have a range of impacts on electricity markets, which in turn will impact on the wider economy through changes to electricity prices charged to end-users. Encouraging renewable energy through a market mechanism will have two direct impacts on the electricity market. First, investment in new renewable energy generation will impact on wholesale electricity prices either through a higher level of generation capacity or though the displacement of new conventional plant. Second, the cost of certificates created to ensure targets are met will be passed on to liable parties (retailers), which in turn will increase delivered prices to consumers.

Changes to electricity prices for consumers will impact on economic activity in Western Australia, by increasing costs and reducing disposable income. These impacts are discussed in the following section.

Apart from impacts on electricity prices, a renewable energy target will impact on:

- Generation mix, particularly of new generation and the role of renewable energy in this. Timing of new conventional plant will also be impacted.
- Investment in new generation plant and transmission capacity.
- Profit expectations of current generators.
- Carbon emission projections.

3.1 Overview

Renewable energy targets will impact on the electricity market as there will be minimal uptake of renewable energy without additional government support. Electricity market impacts are driven by the impact of a higher level of renewable energy generation on electricity prices, as it is electricity prices that drive investment in new conventional generation capacity. The timing of additional renewable energy generation capacity is determined on the basis of minimising costs to meet the target, which in turn will be driven by the combination of electricity prices received and prices for RECWAs.

Under a business-as-usual world with no renewable energy target and no strategic bidding, wholesale electricity prices are modelled to decline over the next few years. This is due to surplus new capacity known to be coming into the market over the next two years. Prices then recover slowly as demand grows and supply tightens and as higher carbon prices are imposed. Additional new investment in generation occurs from 2013 onwards, and this is likely to be mostly conventional generation in the period to 2020, as the carbon prices and hence electricity prices are not sufficiently high enough to encourage renewable energy generation.

Imposing renewable energy targets appears to have complicated impacts on the electricity market. On average, prices are likely to be slightly lower through a combination of

factors, including exacerbating the initial surplus of generation capacity expected in the near term, encouraging investment in new (renewable energy) generation capacity earlier than occurs in the business-as-usual scenario and easing the carbon abatement task.

However, the slightly lower wholesale electricity prices are more than offset by the cost of purchasing certificates. Certificate prices of at least $10/MWh are required to ensure the renewable energy targets. Assuming the cost of purchasing certificates is spread across all liable customers, the average cost of certificates is greater than the small decrease in wholesale electricity prices, so that liable customers experience a small increase in the price of electricity.

Obviously, there is a greater level of investment in renewable energy generation. Investment in conventional generation is deferred, but conventional generation capacity still grows under all of the targets examined in this study.

Impacts on incumbent generators are also complicated. Renewable energy targets tend to depress the wholesale price received by incumbent generators. But the renewable energy target also defers the entry of new high load duty plant, which can lead to more generation by incumbent plant.

The higher capital costs of renewable energy generation mean that economic resource costs (capital, fuel, labour and material costs) are higher with the renewable energy target. This leads to a reduction in net wealth in the short to medium term.

The robustness of the results decreases as the target increases. This is because the renewable energy generation required to meet the lower targets (10% and 15%) is well defined, with operating characteristics and costs based on published data for known projects. As the target increases beyond 15%, there is less certainty about the cost of additional renewable energy generation and also on non-economic limits that may inhibit additional renewable energy generation, such as limits to how many wind farms can be located in one region, intra-regional transmission limits and biomass fuel constraints. Nonetheless, the analysis provides a useful indication of the potential impacts for a 20% target.

3.2 Business-as-usual outcomes

As a prelude to the discussion of the impacts of the renewable energy targets, below we discuss the predicted outcomes in a business-as-usual scenario with no renewable energy targets. Two business-as-usual scenarios were modelled: one with a low carbon price and one with a high carbon price.

Wholesale electricity prices with no renewable energy target and either high or low carbon prices are shown in Figure 3-1. Prices are expected to ease over the period to 2012, as new generation comes on stream at a capacity that exceeds demand growth[14].

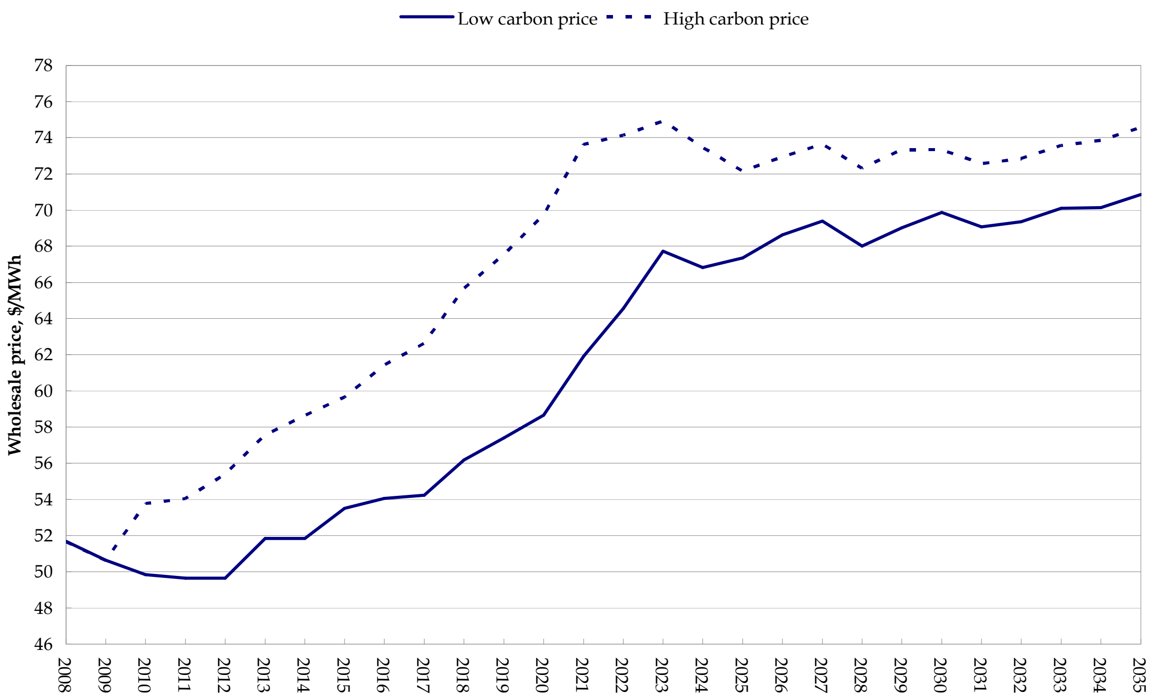
[14] The wholesale electricity prices reported in this study are an average of trading prices plus revenue earnt from capacity payments weighted by generation levels.

From 2010, prices are expected to rise due to a combination of factors:

- Tightening supply demand balance as the capacity surplus dissipates and older plant retire.
- Increases in fuel prices as current gas contracts expire or more fuel (than covered under existing gas contracts) is required.
- Impact of carbon prices, which increases generation costs.

The price predictions should be treated with caution for several reasons. First, competitive bidding by generators is assumed, which means that generators bid in the STEM at short run marginal costs[15]. Depending on the evolution of the market and the level of competition, competitive pressure may be less than assumed and generators may be able to extract higher prices from the market than short run marginal cost pricing would suggest. Second, carbon prices may be lower or higher than assumed, depending on the emission cap settled on by the State or Federal Governments. Third, fuel prices may differ from what is assumed in the analysis. In particular, there is uncertainty over future gas prices, which are crucially dependent on movements in world LNG prices, which in turn depend on movements in crude oil prices. Finally, demand growth may be higher or lower than assumed in the analysis.

Figure 3-1: Wholesale electricity prices with no renewable energy targets



No new renewable energy generation plant is expected to enter the market. Natural gas and coal based generation dominate the generation mix. As shown in the following charts, both natural gas and black coal generation is predicted to increase over time. The

15 Whereby all generators bid in at their short run marginal costs.

increase in coal-fired generation comes about largely from additional new coal-fired capacity coming onstream operating at high load duty. Although new gas-fired plant are confined to peaking duty due to the assumed high gas prices, the presence of carbon prices allows for switching from coal-fired generation to gas-fired generation. Renewable energy generation remains relatively steady, experiencing a small fall in generation levels in the period to 2020, due to the retirement of existing landfill gas plant.

Figure 3-2: Generation by technology type – low carbon price

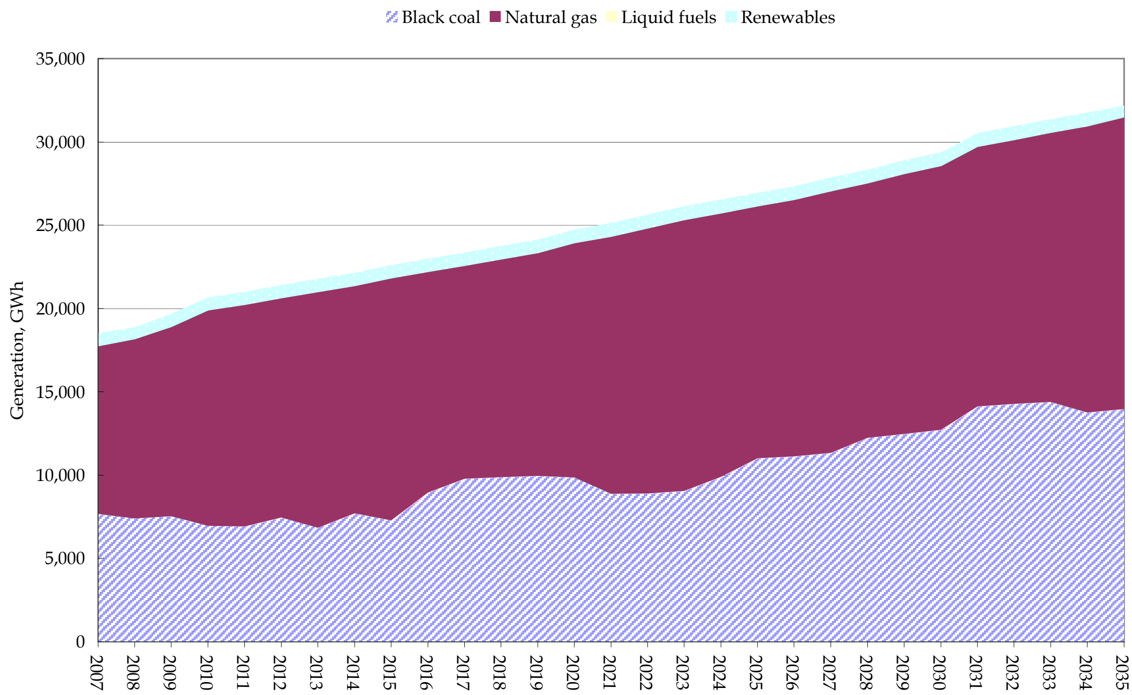
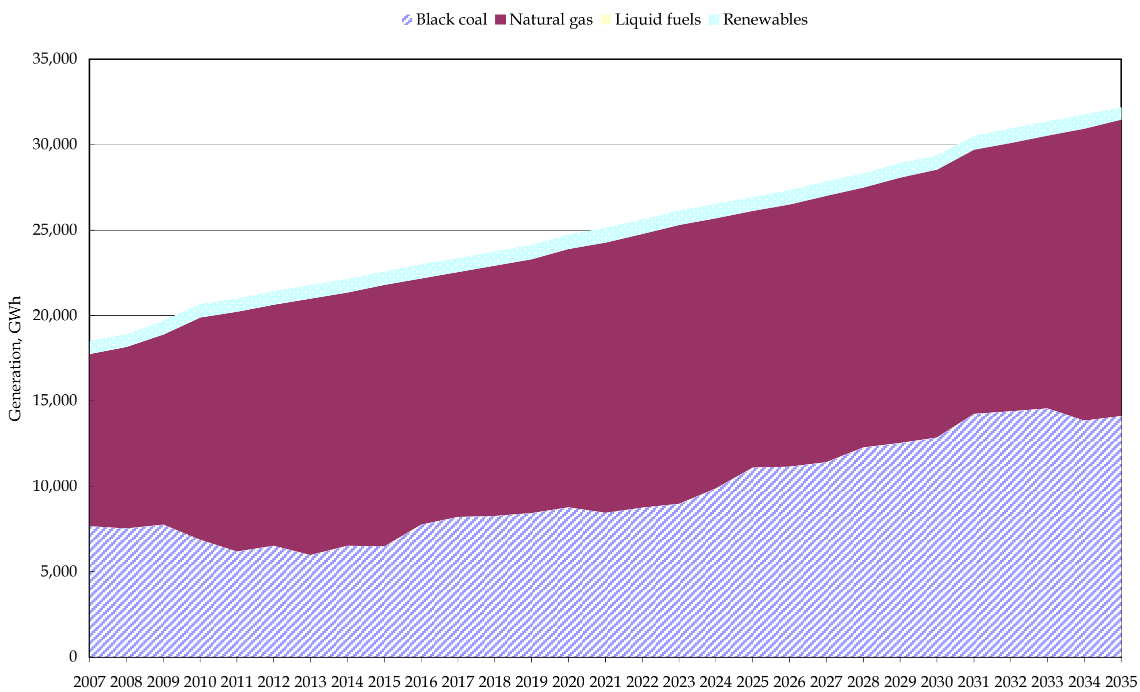


Figure 3-3: Generation by technology type – high carbon price



As a result of the predominance of fossil fuel generation, emissions of greenhouse gases are expected to continue to grow. Imposing carbon prices leads to more gas-fired generation and this moderates any increase in emissions. Emissions are predicted to grow by an average of 1.7% per annum, from 13 Mt per annum in 2007, to 21 Mt per annum in 2035.

Figure 3-4: Emissions from combustion of fuels in electricity generation

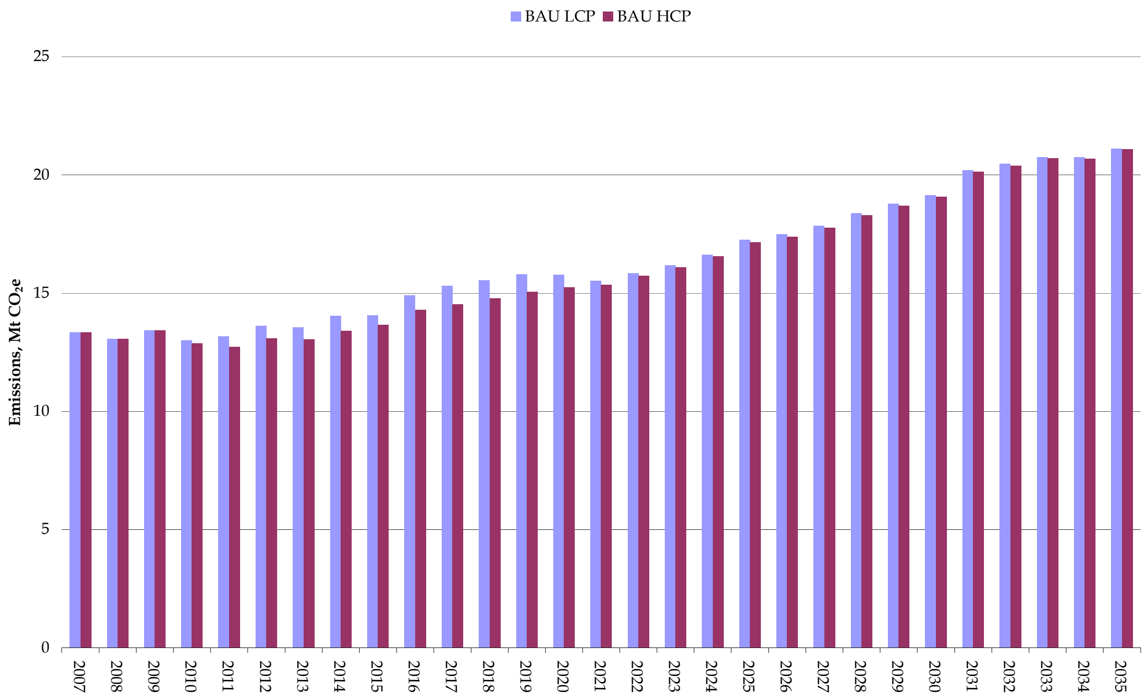


Exhibit 1: National emissions trading

The assumption of national emissions trading serves to increase the cost of electricity generation from greenhouse intensive energy sources in the business-as-usual scenarios. Gas has a lower greenhouse emissions intensity than coal, and consequently gas-fired generation is projected to meet a comparatively greater share of the load.

Carbon prices also increase the comparative competitiveness of renewable energy electricity generation technologies, which are assumed to produce no net emissions. However, the carbon prices assumed in this study are not sufficient to significantly increase the amount of renewable energy generation in the base case scenarios. This is due to the higher cost of renewable energy technologies in comparison to a range of other abatement options. Cheaper options are expected to determine the price of emissions permits, at the levels of national emissions reductions canvassed to date by the National Emissions Trading Taskforce. This feature of renewable energy technologies is discussed further in Section 4-1.

Greenhouse gas emissions in the SWIS in the business-as-usual scenarios are expected to be 5 to 8 per cent lower in 2020 due to the impact of national emissions trading on the generation technology mix. However, modelling by the National Emissions Trading Taskforce suggests that comparatively more abatement is undertaken in other states and territories. This is due to the availability of lower cost abatement options available within these jurisdictions. As discussed in Section 4-1, a SWIS renewable energy target will displace national abatement effort in other sectors and jurisdictions, but may not reduce national emissions overall.

In the absence of carbon pricing, the modelling approach and assumptions suggest medium to long-term wholesale electricity prices would range between $44/MWh and $51/MWh. Wholesale electricity prices in this study are higher by 28% to 40% between 2009 and 2035 (see Figure 3-1) as a result of the assumed carbon price projections.

In this study, carbon pricing is assumed to flow through to consumers and no account is made for any price and financial impact of mitigation measures under consideration by the National Emissions Trading Taskforce. The overall impact of the projected price rises is equivalent to an immediate retail price increase of 17% to 24%. These figures are comparable with the average impact in Table 3-2, and illustrate that, in terms of order of magnitude, national emissions trading is a more significant issue for electricity consumers. However, as indicated by the results in Table 3-2, a renewable energy target scheme will serve to further increase retail electricity costs for most electricity consumers.

Overall, the deeper the reductions in national carbon emissions, the smaller the additional economic and stakeholder impact of a SWIS renewable energy target scheme. This is because renewable energy technologies become comparatively more competitive with conventional generation technologies, and the marginal cost of introducing them into the generation mix is smaller. In effect, as carbon prices increase, a portion of the costs of supporting renewable energy generation is borne by electricity consumers through the national carbon pricing mechanism. The impacts on electricity prices and the economy presented in this study are additional to those assumed to arise as a consequence of national emissions trading.

A sensitivity analysis was conducted that considered the impacts of renewable energy targets in the absence of any future carbon pricing. This is an unlikely scenario because it supposes no commercial value is placed on reducing greenhouse gas emissions in the SWIS at any time in the foreseeable future.

The sensitivity analysis suggests retail price impacts could be 2 to 3 times larger in percentage terms, in the absence of a national emissions trading scheme. The impacts on GSP and employment growth of a 15 per cent target remain small. On the other hand, the quantum of greenhouse reductions in the SWIS due to the target is greater. See Appendix C for a summary of the results of the sensitivity analysis.

3.3 WA renewable energy certificate market prices

Certificate prices under the scenarios modelled are shown in Figure 3-5 and Figure 3-6. Features of the results include:

- In most scenarios a consistent pattern emerges. Certificate prices fall from 2009 until around 2013 to 2016. Thereafter, certificate prices rise until 2020 and then remain steady for the remaining years of the scheme. The initial fall in price arises because there is a limited demand for certificates for banking to meet future liabilities. As there are limited alternative markets, the low targets in the initial years tend to favour small renewable energy generators who can closely match market demand (i.e. the targets), but who have relatively higher marginal costs. Furthermore, electricity prices are lower in this period due to overhang of generation capacity in the market, so that higher certificate prices are required to cover the cost of renewable energy generation. As the supply surplus dissipates, electricity prices increase and the certificate price required to bridge the cost gap decreases. The cost of renewable energy generation is also expected to fall, as a result of improved economies of scale in production of generation equipment and technical advances. Eventually, however, more expensive renewable energy options are required to meet the rising target and certificate prices rise in response.

- The higher the target, the higher the certificate price. Higher targets require more expensive renewable energy generation.

- The increase in price from the 10% target to the 15% target is greater than the increase in price from the 15% target to the 20% target. This is a function of the change in long run marginal costs as a function of generation required (see Figure 2-2). The increase in renewable energy generation required to go from a 10% to 15% target occurs over a portion of the supply curve where there is a relatively steeper increase in long run marginal costs. Going from 15% to 20% occurs in a portion of the supply curve where there is a flatter increase in the long run marginal cost. Note, however, the cost of generation may be higher than assumed in this study as network costs could be higher and system stability impacts could be greater than assumed with higher targets. If these costs are higher than assumed and are passed on to renewable energy generators, certificate prices would be higher than predicted.

- The certificate price falls with rising carbon prices. Carbon prices increase the cost of generation and hence electricity prices received by renewable energy generators in the WEM. Thus, lower certificate prices are required to bridge the gap between the electricity price and the long run marginal cost of renewable energy generation.

- The higher the carbon price, the narrower the difference in the price of certificates between the 15% and 20% targets. The higher the carbon price, the greater the incentive to bring on renewable energy generation early, allowing a greater level of banking and a lower overall level of renewable energy generation capacity.

Figure 3-5: Certificate price with low carbon price

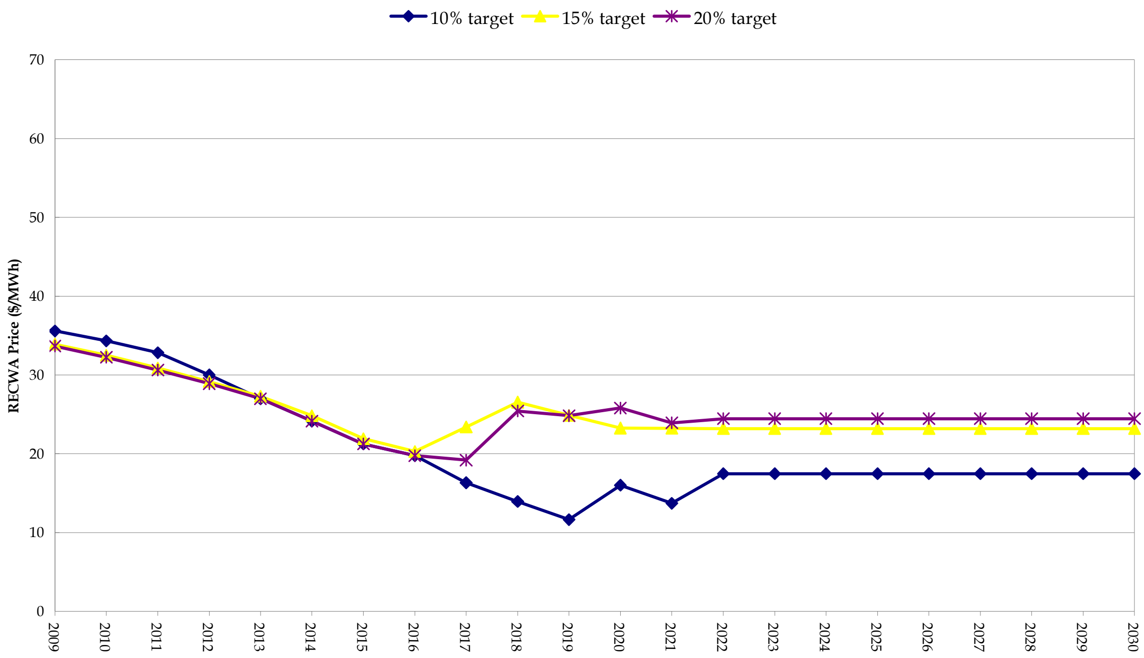
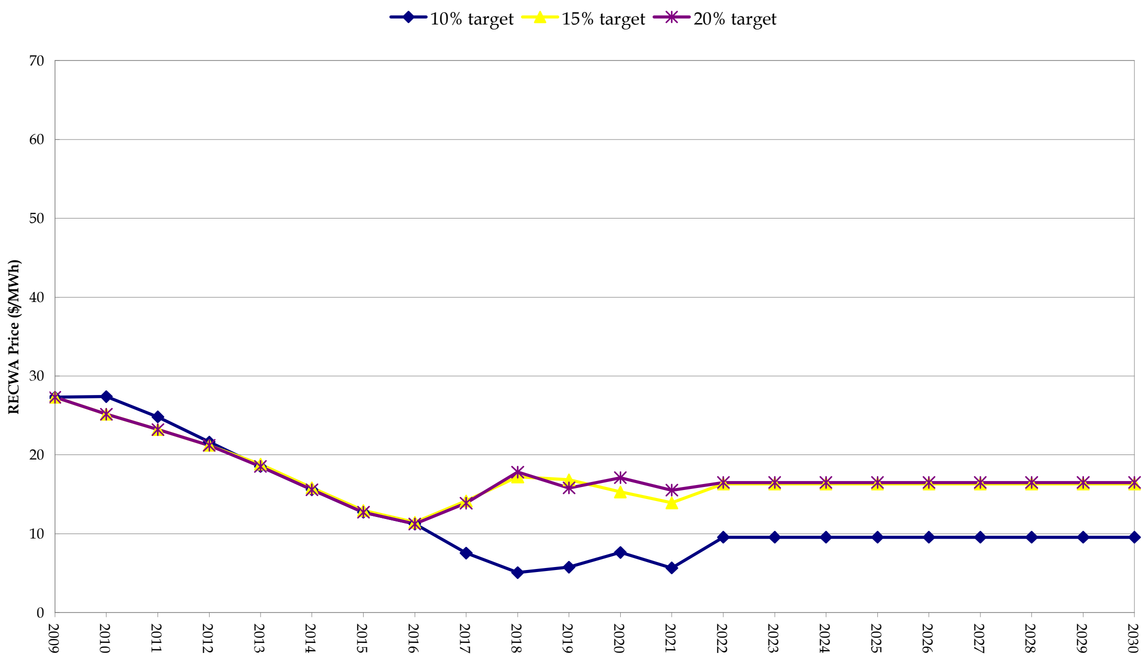


Figure 3-6: Certificate price with high carbon price



3.4 Impacts of renewable energy targets

The impacts on electricity prices are shown at three levels. First, wholesale electricity prices without the certificate price impost added. This reflects the impact on wholesale electricity prices to trade-exposed energy intensive customers who are not liable entities under RETWA. Second, wholesale electricity prices with the certificate price added,

which reflects the impact on electricity purchases by liable retailers. Finally, the impact on retail prices (which include not only the impacts on wholesale prices and the purchase of certificates, but also the impacts of any charges to cover the administration of RETWA and impacts on retailer margins) for all customer classes.

3.4.1 Wholesale electricity prices

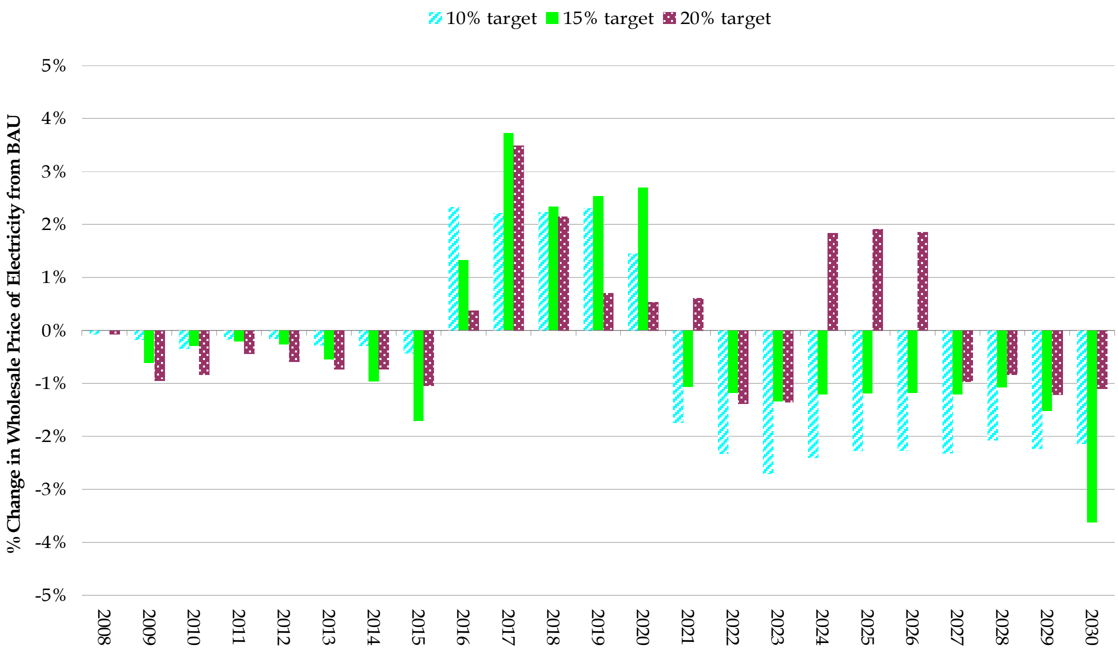
Changes to wholesale electricity prices as a result of renewable energy targets are shown in Figure 3-7 and Table 3-1. On average, wholesale electricity prices tend to be lower with renewable energy targets for three reasons.

First, additional renewable energy capacity to the period to 2013 tends to exacerbate the capacity surplus in this period.

Second, the addition of renewable energy plant defers capacity expansion plans for new thermal plant. The choice of new conventional generation plant is likely to go from least cost to highest cost option. Deferring the entry of new plant means that, in any year, a lower cost option would now be available than in the same year in the business-as-usual scenario. The additional renewable energy generation displaces growth in conventional generation and, hence, extends the investment cycle and delays higher prices associated with tight capacity constraints.

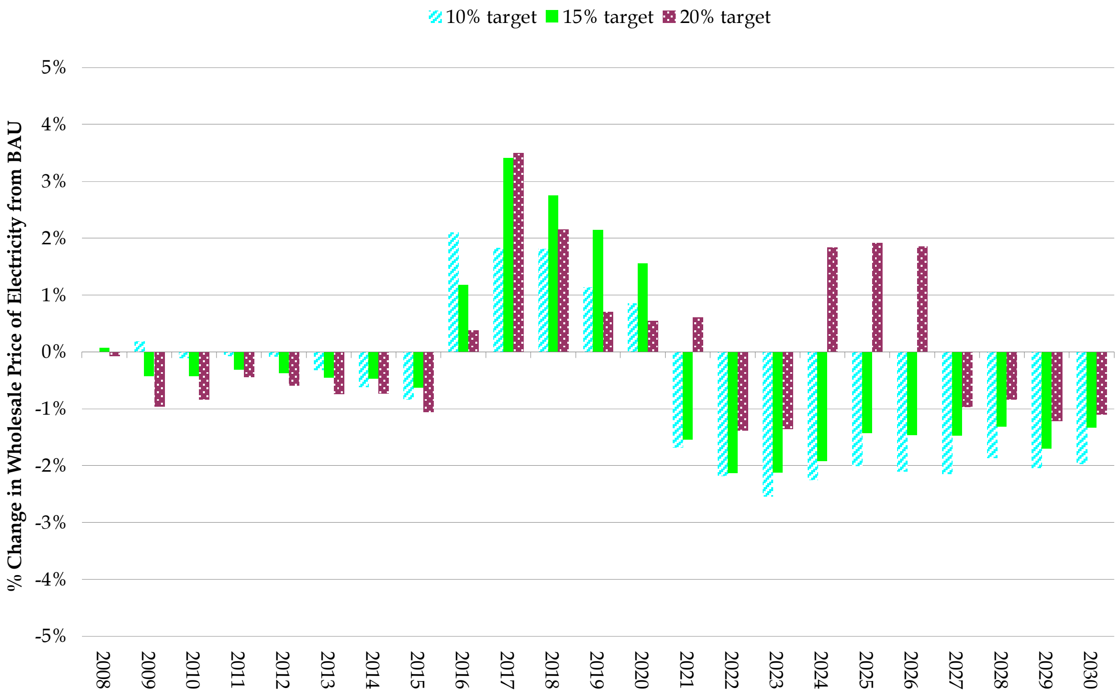
Third, renewable energy generation is dispatched at very low marginal costs, shifting the dispatch curve downwards in a regime with short run marginal cost pricing. Conventional generation will be displaced at the margin through the market.

Figure 3-7: Changes to wholesale electricity prices with low carbon prices



Source: MMA analysis.

Figure 3-8: Wholesale electricity prices with high carbon prices



Similar trends are observed with low and high carbon prices. Wholesale prices are higher with high carbon prices than with low carbon prices. On average, renewable energy targets tend to depress prices over the study period in both the high and low carbon price cases.

Whilst wholesale electricity prices tend to be lower on average, there are periods where prices are higher. For all targets, electricity prices are higher in the period from 2015 to 2020, reflecting a change in profile of new generation with a delay in a new coal plant by four years. This leads to higher cost plants being dispatched more often in this period.

Table 3-1: Changes to wholesale electricity price, % increase on business-as-usual levels

	2009-2020	2021-2035	2009-2035
RET 10% Low carbon price	0.7%	-2.2%	-0.9%
RET 15% Low carbon price	0.7%	-2.1%	-0.9%
RET 20% Low carbon price	0.2%	-0.9%	-0.4%
RET 10% High carbon price	0.5%	-2.0%	-0.9%
RET 15% High carbon price	0.7%	-1.2%	-0.4%
RET 20% High carbon price	-0.3%	-1.3%	-0.8%

Source: MMA analysis. Note scheme liabilities end in 2035. The period 2009-2020 is the ramp up phase, when the renewable energy target is progressively increased to the ultimate target. During 2021-2035, the scheme continues to operate with certificates for renewable energy generators continually being generated under the 15 year eligibility terms of the scheme. The scheme slowly winds down from 2025 onwards. Price changes are calculated for average real prices over the specified periods. Prices with a renewable energy target are compared with prices in the business-as-usual scenario with the same carbon price.

Prices for the 10% RETWA are also significantly lower than the other targets in the period from 2020 to 2035. The model is optimising the timing of the entry of large new base load capacity, and the timing of entry under different renewable targets is different depending upon how much conventional generation is displaced. With a low renewable energy target, the additional renewable energy generation may not be sufficient to defer entry of new base load plant, so there is additional capacity servicing the market. The additional capacity leads to downward pressure on prices.

However, as the level of renewable energy generation increases (with the 15% target or 20% target), a larger portion of new generation needs is covered by the renewable energy generation including base load needs, so that the need for new coal plant is deferred until later on. Thus, there is a smaller price fall with these targets in the period from 2020 to 2030.

On average over the period to 2035, wholesale electricity prices are around 0.4% lower to 0.9% lower than in the reference scenarios. Given the vagaries of predicting wholesale market prices and the potential for different behaviour by market participants than assumed in this analysis, we would caution that the best way to interpret the results is to suggest that the impact of the RETWA on wholesale market prices is likely to be small in the long-term.

When the certificate cost is added to the wholesale price[16], the cost of purchasing electricity increases overall. The combination of the wholesale price plus certificate costs[17] leads to the cost of purchasing electricity on the wholesale electricity market increasing, on average, by less than 1% higher for a 10% target, less than 2% higher for a 15% target and less than 4% higher for a 20% target.

3.4.2 Retail prices

Retail prices are shown in Table 3-2. Liable customers pay a higher price due to the fact that the cost of purchasing certificates is greater than the reduction in wholesale electricity prices caused by the impact of the target on the wholesale electricity market. The price increase to these customers is less than 3% on average, or $2.70/MWh or less.

Electricity prices to trade exposed and energy intensive customers are generally lower with a renewable energy target. This is due to the fact that they enjoy the resulting lower wholesale electricity prices, but do not incur a liability under RETWA. Instead, their liabilities are met by other consumers. The decrease in price is less than 0.6% averaged over the period from 2009 to 2035. The saving amounts to less than $2/MWh.

[16] This is done by multiplying the certificate price by the number of certificates purchased divided by the total wholesale electricity sales.

[17] With the cost of purchasing certifictes spread over all elextricity sales.

Table 3-2: Retail price increases by customer class, increase on business-as-usual levels

	2009- 2020, % increase	2021-2035, % increase	2009- 2035, % increase	Average, $/MWh	Average %
Energy Intensive and Trade Exposed					
RET 10% Low carbon price	0.62%	-1.95%	-0.81%	-0.50	-0.46%
RET 15% Low carbon price	0.57%	-1.84%	-0.76%	-0.44	-0.41%
RET 20% Low carbon price	0.15%	-0.75%	-0.35%	-0.19	-0.18%
RET 10% High carbon price	0.43%	-1.81%	-0.82%	-0.54	-0.50%
RET 15% High carbon price	0.58%	-1.04%	-0.32%	-0.21	-0.19%
RET 20% High carbon price	-0.26%	-1.07%	-0.71%	-0.50	-0.46%
Industrial					
RET 10% Low carbon price	1.31%	-1.05%	0.00%	0.11	0.11%
RET 15% Low carbon price	2.23%	0.24%	1.12%	1.09	1.00%
RET 20% Low carbon price	2.61%	2.27%	2.42%	2.12	1.96%
RET 10% High carbon price	0.76%	-1.28%	-0.37%	-0.21	-0.19%
RET 15% High carbon price	1.49%	0.24%	0.80%	0.79	0.72%
RET 20% High carbon price	1.18%	0.93%	1.04%	1.02	0.94%
Commercial					
RET 10% Low carbon price	0.94%	-0.81%	-0.03%	0.12	0.11%
RET 15% Low carbon price	1.60%	0.17%	0.80%	1.12	1.03%
RET 20% Low carbon price	1.87%	1.72%	1.79%	2.19	2.02%
RET 10% High carbon price	0.56%	-1.00%	-0.30%	-0.22	-0.20%
RET 15% High carbon price	1.10%	0.19%	0.59%	0.81	0.75%
RET 20% High carbon price	0.87%	0.71%	0.78%	1.05	0.97%
Residential					
RET 10% Low carbon price	0.82%	-0.73%	-0.04%	0.12	0.11%
RET 15% Low carbon price	1.40%	0.15%	0.71%	1.15	1.06%
RET 20% Low carbon price	1.64%	1.54%	1.59%	2.25	2.07%
RET 10% High carbon price	0.50%	-0.90%	-0.28%	-0.22	-0.21%
RET 15% High carbon price	0.98%	0.17%	0.53%	0.83	0.77%
RET 20% High carbon price	0.77%	0.64%	0.70%	1.08	1.00%

Source: MMA analysis. The increases represent the percentage increases in delivered electricity prices over different phases of the scheme, averaged over the specified period. The average impact is the overall price impact in present value terms, from now until the end of the scheme in 2035. Price changes are calculated for delivered prices, which included wholesale electricity market purchase costs (including RECWA costs), network fees, retailer margins and costs for administering the RETWA scheme (assumed to be $1/MWh in line with the costs of running MRET). Prices with a renewable energy target are compared with prices in the business-as-usual scenario with the same carbon price.

Using a conservative assumption of no decrease in wholesale electricity prices and that the full cost of purchasing certificates is passed on to retail customers, the additional expenditure on electricity is shown in Table 3-3. The additional expenditure is less than $13/year. For a small business, the additional expenditure is less than $70/year. For large businesses that are liable to comply with RETWA, the increase in expenditure is

about $52,000/year. Of course, once the decreases in wholesale prices are factored in, then the net increase to these customer groups are lower than these estimates.

If the reduction in wholesale electricity prices is passed through to retail customers, the additional expenditure on electricity will be lower than estimated in Table 3-3.

Table 3-3: Additional expenditure on electricity purchases, $/year

	Household	Small business	Large business
RET 10% High carbon price	1.9	10	7,439
RET 10% Low carbon price	3.4	19	13,705
RET 15% High carbon price	5.6	31	22,465
RET 15% Low carbon price	8.4	46	33,712
RET 20% High carbon price	8.4	46	33,792
RET 20% Low carbon price	12.9	70	51,421

Note: Average household is assumed to consume 5.5 MWh, average small business is assumed to consume 30 MWh and an average large business is assumed to consume 22,000 MWh. Additional expenditure is the cost of renewable energy certificates to an average consumer, in present value terms, expressed as an equivalent percentage increase in annual electricity expenditures from now until the end of the scheme in 2035.
Source: MMA analysis based on household consumption data provided by the ESAA.

3.4.3 Generation mix

The objective of the renewable energy target is increased capital investment in renewable energy generation capacity (see Figure 3-9). The investment is spread reasonably over the period to 2022, suggesting that the scheme could provide adequate incentives to fund a renewable energy industry for over a decade. In present value terms, the investments in renewable energy generation over the period from 2009 to 2035 are estimated to be:

- $477 million for a 10% renewable energy target with low carbon price.
- $1,054 million for a 15% renewable energy target with low carbon price.
- $1,496 million for a 20% renewable energy target with low carbon price.
- $688 million for a 10% renewable energy target with high carbon price.
- $1,198 million for a 15% renewable energy target with high carbon price.
- $1,740 million for a 20% renewable energy target with high carbon price.

Figure 3-9: Investment in renewable energy generation capacity, low carbon price

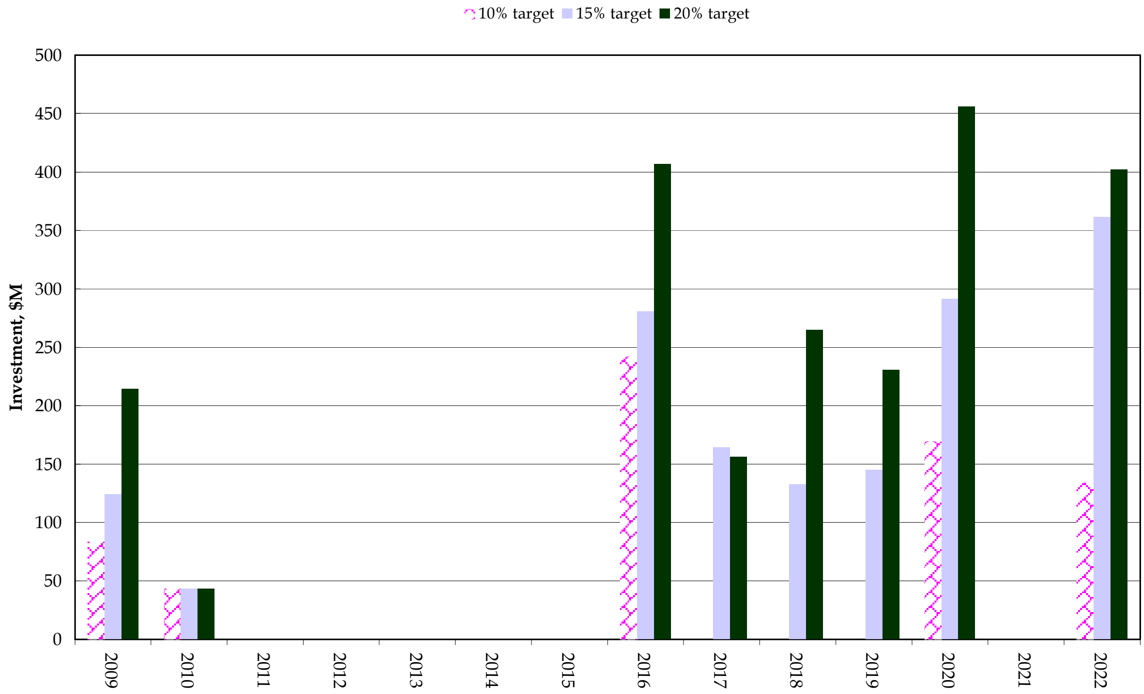
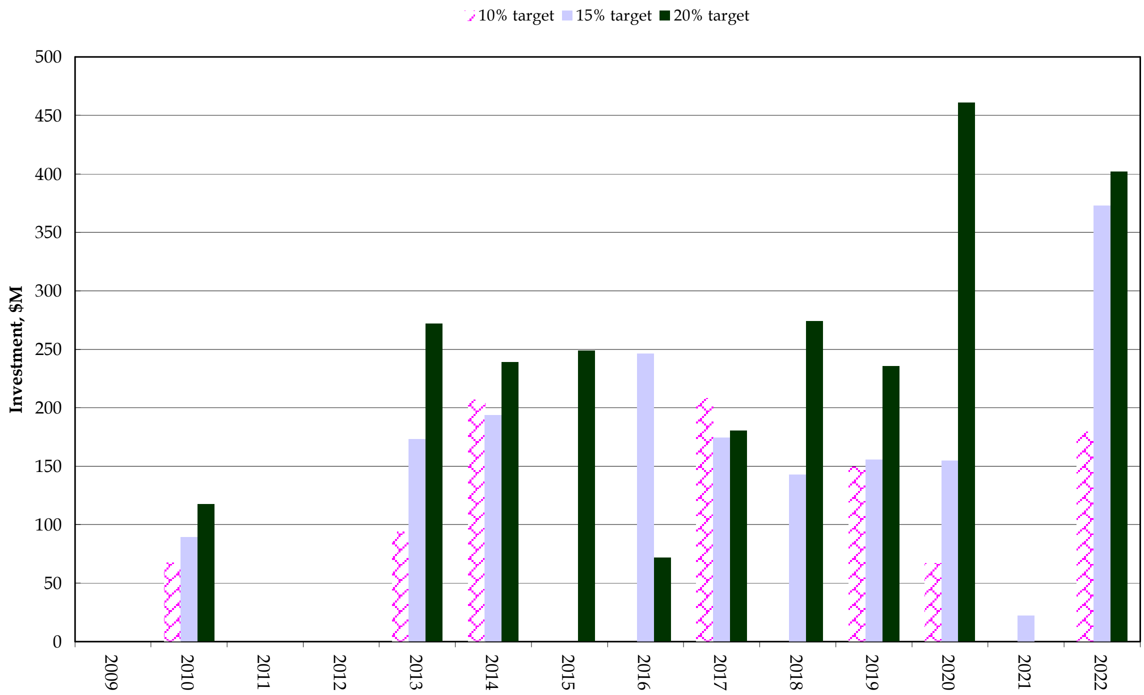


Figure 3-10: Investment in renewable energy generation capacity, high carbon price



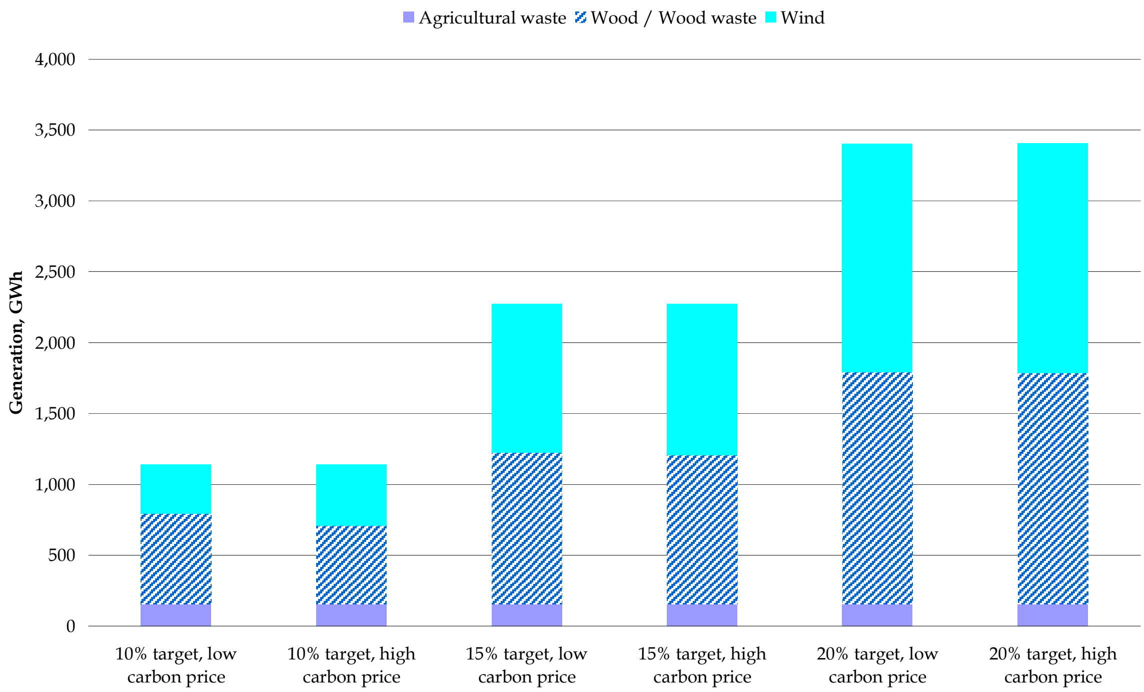
Even though there is little apparent difference between the high and low carbon scenarios for each target level, in terms of output from renewable energy generation, there is still some difference in the present value of investments. The higher level of investment in the high carbon price case reflects two factors. First, the bringing forward of investment in

some renewable energy generation in the period before 2018. The profile of investment differs, with investment in the period to 2018 being typically brought forward with high carbon prices (so that the same investment in the low carbon price scenario tends to be discounted more in the present value calculations). Second, the higher level of renewable energy capacity from 2020 onwards, reflecting a lower level of banking in the period from 2015 to 2020. In summary, renewable energy investment comes forward in the high carbon scenario.

The scheme encourages wind and biomass generation options. The level of biomass generation is relatively higher than for other renewable energy technologies with a 10% target. There are some low cost biomass options, mainly wood waste and agricultural waste options, which are adopted in all target scenarios. The level of biomass generation does not increase as much as for other technologies with the higher targets, with the exception of some additional wood waste based generation being encouraged. Rather, relatively more wind generation is adopted with targets of 15% or higher. This outcome is likely to be highly sensitive to the assumptions underpinning the fuel costs for biomass projects.

Additional wind generation tends to enter the market from 2013 onwards. Thus, any impacts on the grid associated with increasing levels of intermittent generation are not likely to manifest until later on in the next decade.

Figure 3-11: Eligible renewable energy generation by technology type in 2020



Note: This chart shows for each target the additional renewable energy generation (sent out from generator) above business-as-usual levels. Transmission losses of 5% have to be deducted to determine certificates that can be earnt from this generation. Banking means additional generation capacity may come on line is some scenarios soon after 2020 to meet liabilities from 2020 to 2035.

The uptake of additional renewable energy under RETWA also results in a change in the pattern and timing of investment in new fossil fuel generation and reduces the level of generation from fossil fuel plant against business-as-usual.

Fossil fuel capacity under each renewable energy target is shown in Figure 3-12. Capacity in 2020 is lower by around 70 MW for a 10% target, 200 MW for a 15% target and 270 MW for a 20% target. Capacity in 2030 is lower by 130 MW for a 10% target, 200 MW for a 15% target and 330 MW for a 20% target. This is less than half of the increase in renewable energy capacity under each target, reflecting the fact that some forms of renewable energy generation are intermittent and therefore have lower levels of firm capacity.

The renewable energy target also changes the mix of new fossil fuel plant. In most scenarios, new coal plants are deferred and there is typically one less new coal plant by 2030. Although there may be some deferment of new gas plant, typically there is no reduction in the number of gas plant by 2030 for targets less than 20% and deferral of one gas plant for a target of 20%.

Increasing the level of renewable energy generation also decreases the level of fossil fuel generation both due to the deferment of new capacity and the displacement of existing plant in the dispatch order of plants. Fossil fuel generation continues to grow, but at a slower pace with a renewable energy target. For example, black coal generation increases by an average of 1.9% per annum under business-as-usual conditions with a carbon price over the period to 2030. With a 10% renewable energy target, the rate of growth over the same period is reduced to 1.7%. With a 15% target, the rate of growth is reduced to 1.5%.

Figure 3-12: Expansion in fossil fuel generating capacity, low carbon price

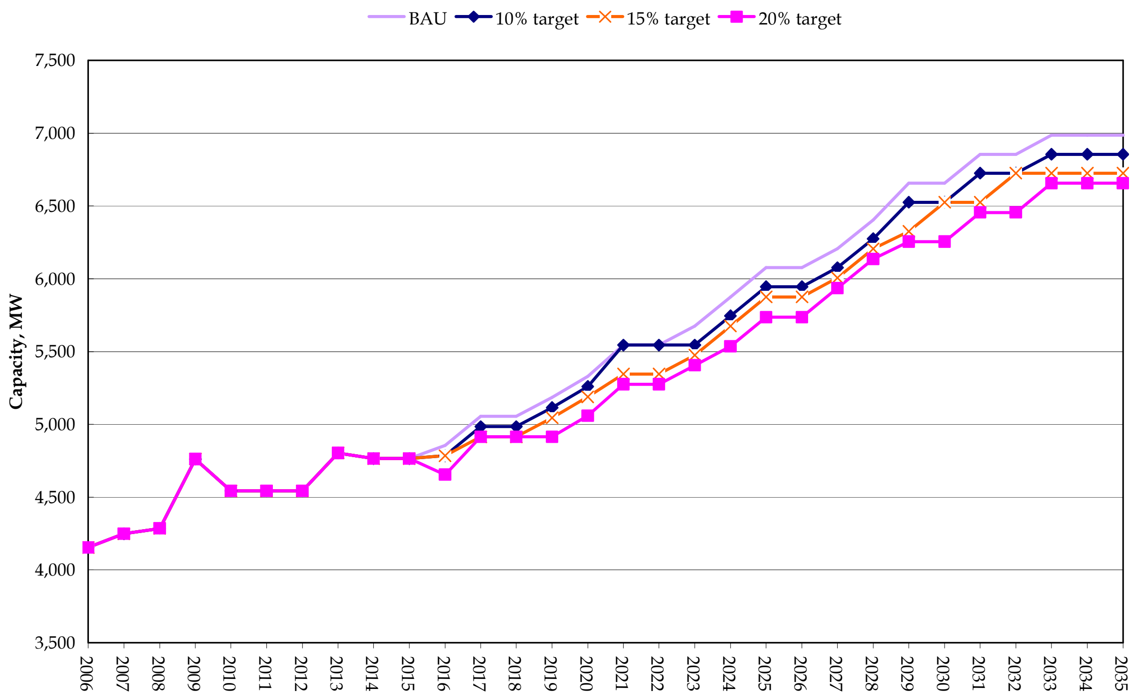


Figure 3-13: Expansion in fossil fuel generating capacity, high carbon price

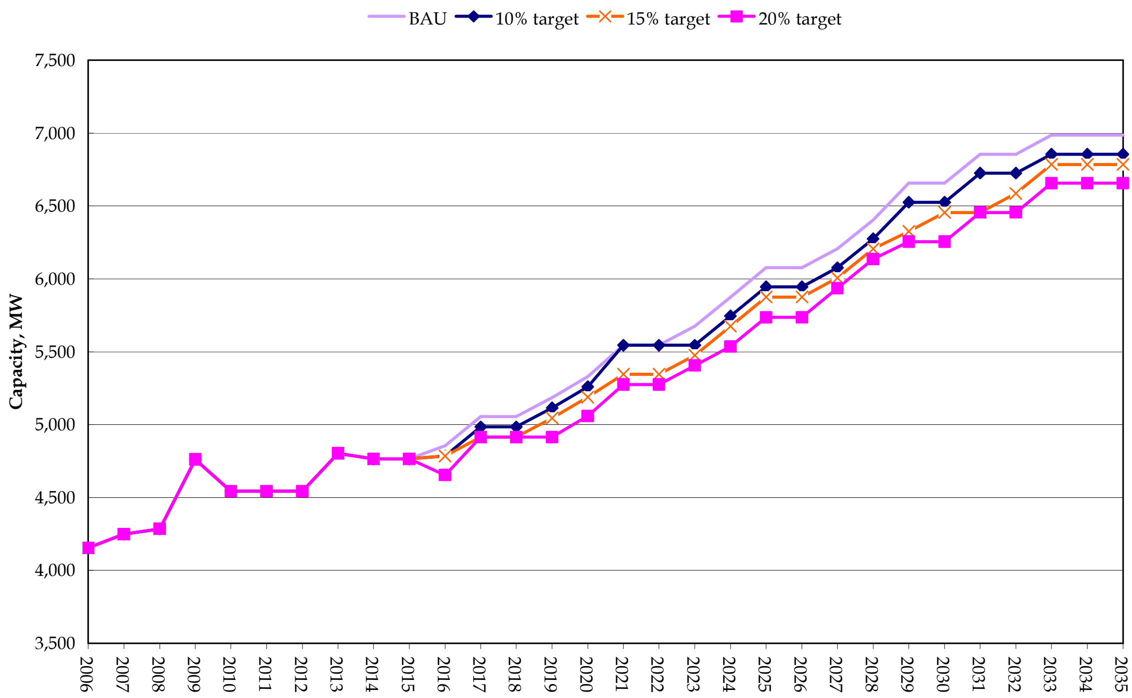


Figure 3-14: Black coal generation with low carbon price

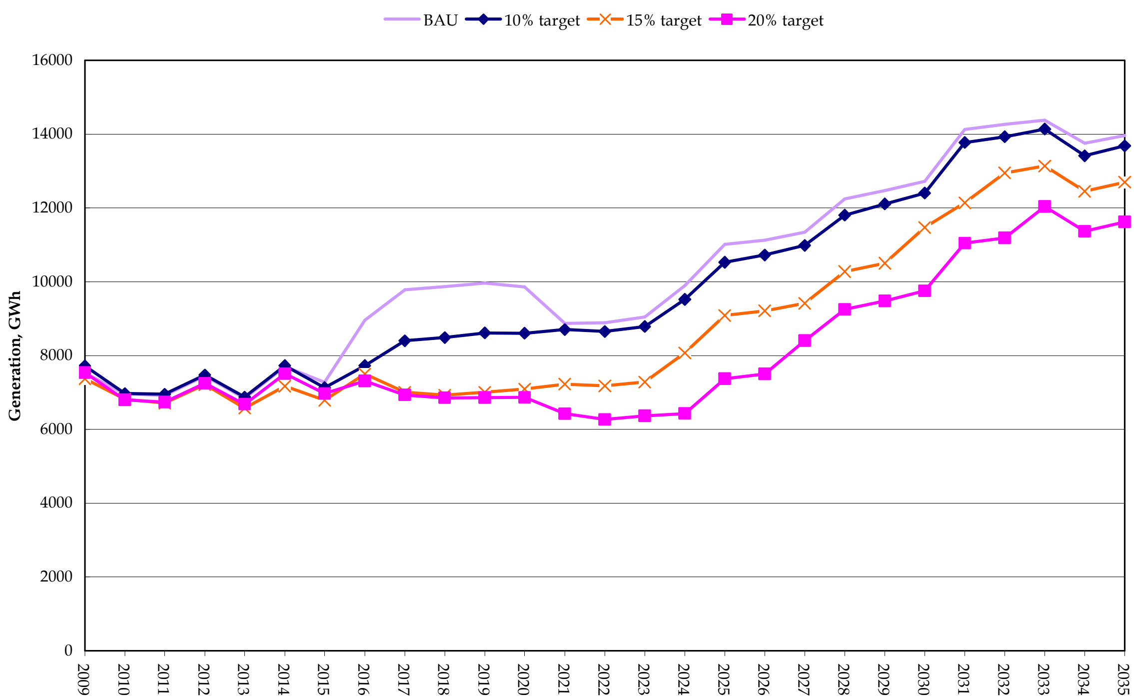
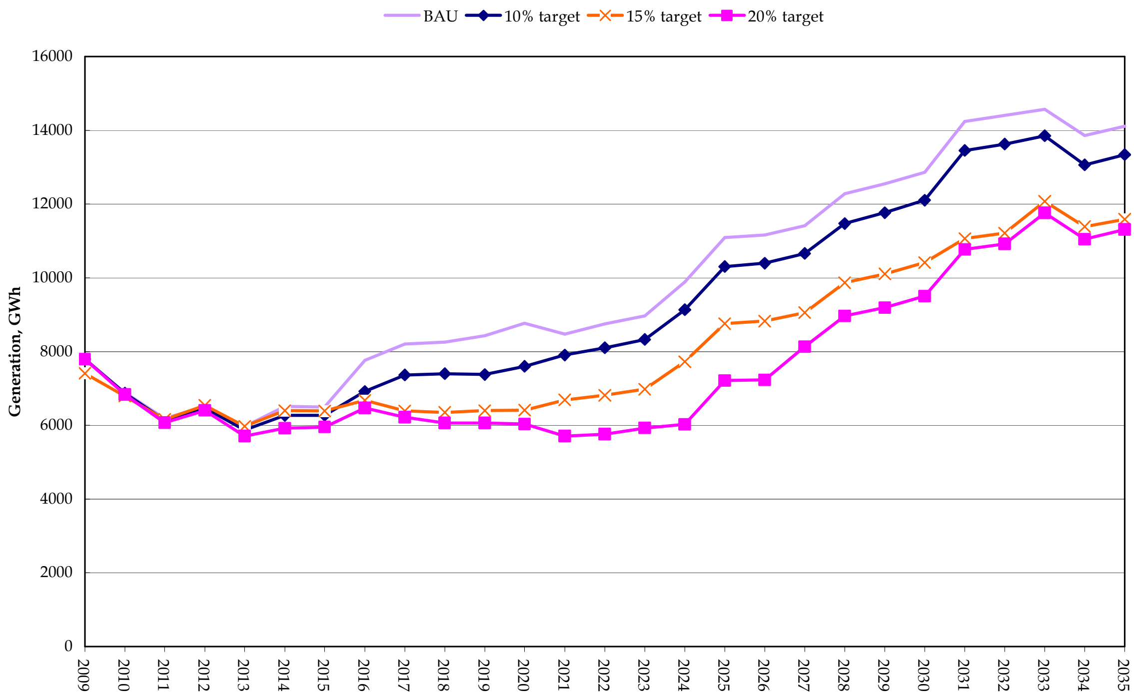


Figure 3-15: Black coal generation with high carbon price



Similarly, gas-fired generation increases by around 2.4% under business-as-usual assumptions with a carbon price. There is very little change in the growth rate of gas-fired generation when there is a renewable energy target, as renewable energy generation mainly affects generation by mid-merit existing coal-fired plant or defers new coal plant. With a carbon price, the growth rate in gas-fired generation falls to around 2.2% per annum with a renewable energy target.

3.5 Generator profitability

Profit making opportunities from existing generation may be affected by the imposition of a renewable energy target. Both prices received on the wholesale market and the level of generation may be affected by a higher level of renewable energy generation.

Impact on profits of incumbent generators has been calculated making the following assumptions:

- Ownership structure does not change from current structures.
- New plants, including new renewable energy plants, are assumed not to be owned by incumbent generation companies.
- Profit impacts are calculated from changes to the volume of generation and prices received for generation for each generating unit. Change in operating profits for incumbent generators is calculated as the sum of changes to operating profits for each incumbent generating unit.

The potential impact on the profitability of existing generation units is shown in Table 3-4. Existing generators include those already operating and those under construction, and include plant owned by Verve Energy, Alinta, Transfield and Griffin Energy.

Table 3-4: Change in profits of existing generators, present value, $M

	2009-2020	2021-2035	2009-2035
RET 10% High carbon price	60	-257	-196
RET 10% Low carbon price	-914	-1,236	-2,150
RET 15% High carbon price	653	1,047	1,700
RET 15% Low carbon price	170	120	290
RET 20% High carbon price	-39	693	653
RET 20% Low carbon price	-534	17	-517

Note: Present values are in mid 2006 dollar terms and are calculated using a 6% nominal discount rate converted into real terms by deflating by an assumed inflation rate of 2.5%. Profits with a renewable energy target are compared with profits in the business-as-usual scenario with the same carbon price.

The level of profit appears to increase (or the level of losses decreases) with rising renewable energy target. A 10% target will incur losses, as the additional renewable energy generation decreases wholesale electricity prices, but will not defer the entry of new generation to any large extent. This extends the period of base load overcapacity, and consequent low WEM prices, expected as a result of projects currently under construction.

In addition, higher targets may depress wholesale electricity prices, but also lead to deferment of new base load coal-fired generators. Although existing generators receive lower wholesale electricity prices with the higher target, the volume of generation by the incumbent generators as a whole increases[18]. The revenues from an increased volume of generation compensate for the impact on revenue of lower wholesale electricity prices.

The estimates of changes to profit need to be treated with caution:

- Strategic bidding has not been assumed in any of the scenarios. Generators may use strategic bidding to minimise the impact on profits of excess levels of renewable energy generation.
- Rational behaviour in the timing that new plant can enter the market has been assumed. Other strategic imperatives may encourage generators to enter earlier or later than indicated in the analysis, affecting profits of other generators in the market.
- Some existing renewable generators expand existing capacity slightly in response to the scheme and hence appear to receive higher profits as a result.
- Some of the existing generators may own the new renewable energy plant and therefore may get some compensation from profits from these plants. In regard to new generation, incumbents are likely to have an advantage in capturing growth in

[18] For some incumbent generators with a portfolio consisting mainly of base load plant, their profits will decrease since they do not get the benefit of increased volumes of generation.

the new renewable energy market. Most of these companies operate across the conventional and renewable energy generation sectors. To the extent that existing companies own new renewable energy and new conventional generation, their profit impacts will differ from that calculated in this study.

- The calculation of profits did not take into account existing contract terms and conditions, which may protect some existing generators from adverse price movements. Technically, there may still be losses, but the losses will be reflected as a foregone opportunity for electricity consumers, rather than a direct impact on financial position in incumbent generators.

4 ECONOMIC IMPACTS

In this section, the impact of the proposed renewable energy target on the Western Australian economy is discussed. Impacts on economic productivity were examined by comparing the resources costs (changes to the amount of capital, fuel, labour and material costs to produce electricity) estimated using the results of the electricity market simulations. The flow-on impacts on the broader economy were determined using the Centre of Policy Studies' computable general equilibrium model of the Australian economy (the MMRF model). The impacts of a target on the broader economy were examined based on the 15% target scenario, as this was the midpoint target of the range of targets examined in this study.

A renewable energy target will lead to a lower rate of economic growth. Gross State Product, a measure of net income of the economy, is reduced by less than 0.01% in 2020. The renewable energy target delays the achievement of projected levels of economic activity by around two weeks in 2020.

Employment goes up in the renewable energy sector. Overall, there is a net reduction in employment growth against reference scenarios, due to the impact of the measure on the broader economy. Employment is lower by around 0.1% in 2020.

4.1 Resource costs and greenhouse gas abatement benefits

Renewable energy is, on average, more expensive per megawatt hour. Dedicating a wedge of growth to a more expensive technology means that more capital, fuel and operating resources are now required to supply a given level of electricity. Furthermore, because electricity is now more expensive, less electricity is likely to be demanded at the expense of more of other substitutable inputs. However, this impact is likely to be minimal because of the inelastic response of demand to small changes in price. The resource cost calculated in this study represents the cost of renewable energy generation, less the avoided cost of conventional generation.

The resource cost of generating electricity includes capital, fuel, labour and material costs. Additional resource costs come from higher capital and, potentially, operating costs. This will be offset to some degree by lower fuel costs for conventional generation.

Estimates of the present value of additional resource costs range from:

- $158 million for a 10% target with low carbon price.
- $463 million for a 10% target with high carbon price.
- $623 million for a 15% target with low carbon price.
- $901 million for a 15% target with high carbon price.
- $818 million for a 20% target with low carbon price.

- $1,156 million for a 20% target with high carbon price.

The estimates of resource costs represent about 1% to 8% of the present value of the total cost of resources used in electricity generation. The resource costs, above, do not include the cost of carbon permits.

The resource cost of the scheme increases with an increased target and with higher carbon prices. Again the difference due to carbon price mainly reflects the fact that investments in renewable energy generation occur earlier in the period to 2018 with higher carbon prices, meaning the impacts on resource costs occur sooner with a higher carbon price. Under the discounting procedure used to calculate the present value, this means that the resource costs that occur later under a low carbon price tend to get discounted more.

However, greenhouse gas emissions in the SWIS are reduced (see Table 4-1) as a result of the renewable energy targets.

Table 4-1: Reduction in greenhouse gas emissions in the SWIS, Mt per annum

Average abatement	2009-2020	2021-2035	2009-2035
RET 10% High carbon price	0.4	0.9	0.7
RET 10% Low carbon price	0.5	0.8	0.7
RET 15% High carbon price	0.7	1.9	1.4
RET 15% Low carbon price	1.0	1.7	1.4
RET 20% High carbon price	1.0	2.8	2.0
RET 20% Low carbon price	1.2	2.8	2.1

Source: MMA analysis.

Without a renewable energy target, the level of abatement occurring as a result of emissions trading in the SWIS is limited in the period to 2020. This is because the high cost of natural gas in Western Australia means that a comparatively high carbon price is required to encourage substitution of gas-fired generation for coal-fired generation. Over the period to 2035, the amount of abatement from emission trading alone is around 31 Mt CO_2e and 23 Mt CO_2e, for the high and low carbon prices respectively.

A renewable energy target would allow Western Australia to contribute further to the emissions reduction task. With a 10% renewable energy target, a further 18 Mt CO_2e is abated in Western Australia over the period from 2009 to 2035. The additional abatement in Western Australia with a 15% target and 20% target is about 37 Mt CO_2e and 55 Mt CO_2e respectively. As the life of many projects developed for the target will exceed the life of the program, further abatement can be expected beyond the scheme expiry date of 2035.

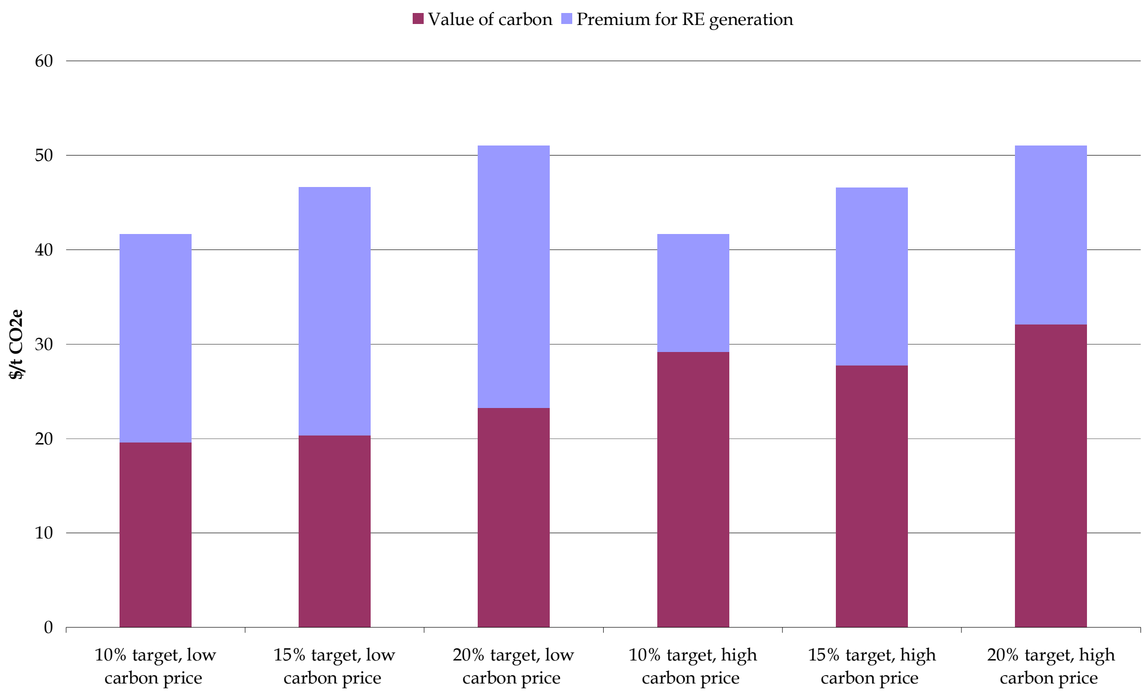
However, overall emissions reductions through a national emissions trading scheme will not increase as a consequence of the RETWA, if a fixed national emissions target is assumed. Rather, the additional greenhouse emissions reductions in the SWIS will reduce the national abatement task. The emissions reductions in the SWIS for the 15% and 20% targets are equal to or more than Western Australia's share of abatement achieved through the assumed national emissions trading regimes.

Estimates of the present value of greenhouse gas abatement as a result of the renewable energy target are:

- $214 million for a 10% target with low carbon price.
- $299 million for a 10% target with high carbon price.
- $433 million for a 15% target with low carbon price.
- $603 million for a 15% target with high carbon price.
- $661 million for a 20% target with low carbon price.
- $903 million for a 20% target with high carbon price.

The cost effectiveness of additional carbon abatement due to the renewable energy targets, which is a measure of the effectiveness of the scheme relative to other carbon abatement measures, is shown in Figure 4-1. The average cost of abatement ranges from \$12/t CO_2e to \$28/t CO_2e, in addition to the assumed value of carbon. Thus, renewable energy in Western Australia is a comparatively high cost form of carbon abatement.

Figure 4-1: Average cost of abatement



Source: MMA analysis. The abatement cost is calculated as the cost of eligible renewable energy generation in each year multiplied by the certificate price (that is, the compliance cost to liable parties). The average cost of abatement is calculated as the present value of the abatement cost to liable parties over the period from 2009 to 2035, divided by the present value of the abatement in each year over the same period. This is likely to be an overestimate of the economic cost of abatement because of the large income transfers from liable parties to intra-marginal renewable energy generators. The value of carbon is recovered as avoided costs under an assumed national emission trading scheme.

The scheme could deliver additional benefits. In particular, the level of renewable energy generation induced by the scheme could lead to lower generation costs in the long-term through the experience gained in dealing with renewable energy generation. One of the

primary reasons for having a renewable energy target is to reduce the costs of renewable energy generation through learning by doing and economies of scale in manufacture. Although it is likely that the manufacture of renewable energy equipment will occur overseas, there is still some learning by doing that could occur in the Western Australian context:

- Learning by installers of equipment.
- Enhancing and improving fuel supply and fuel quality for biofuels.
- Development of unique resources such as geothermal resources.
- Development of ancillary service systems and learning mechanisms to cope with a high level of intermittent generation in the SWIS grid.

Such learning by doing could lead to cost reductions, the benefits of which are difficult to quantify and have not been undertaken as part of this analysis.

4.2 GDP and private consumption

Implementation of a renewable energy target is likely to reduce gross state product (GSP) in Western Australia, and this impact was assessed for a 15 per cent target scheme. The present value of the reduction in GSP in Western Australia over the study period ranges from $296 million for the high carbon price scenario to $835 million for the low carbon price scenario. This represents a reduction of 0.01% to 0.03% of the present value of GSP in Western Australia over the study period.

Economic activity is about 0.07% to 0.11% lower by 2020. Business-as-usual levels of GSP are reached 1.8 weeks later in 2020.

Australia's GDP also falls marginally, although less than Western Australia's GSP reduction. This is because other states and territories benefit somewhat due to the impact that slower economic growth in Western Australian has on the exchange rate and input markets.

Despite the lower rate of growth, the Western Australian economy is still projected to grow by around 3.9% to 4.1% per annum in the period to 2035. Thus, a 15% renewable energy target is consistent with ongoing high levels of economic growth and employment in Western Australia.

Figure 4-2: Impact on GSP in Western Australia

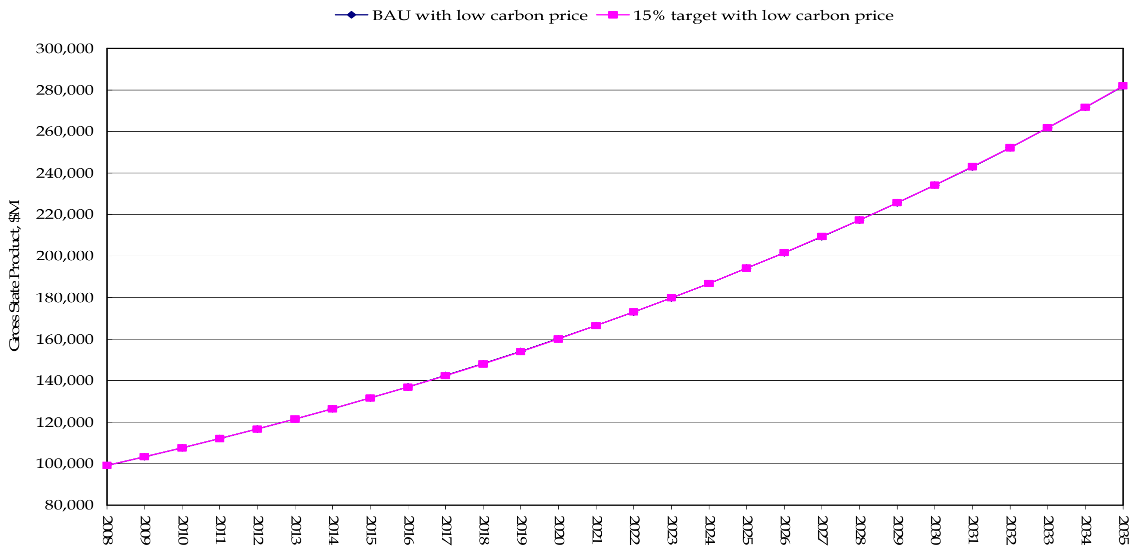


Figure 4-3: Rates of growth in GSP in Western Australia

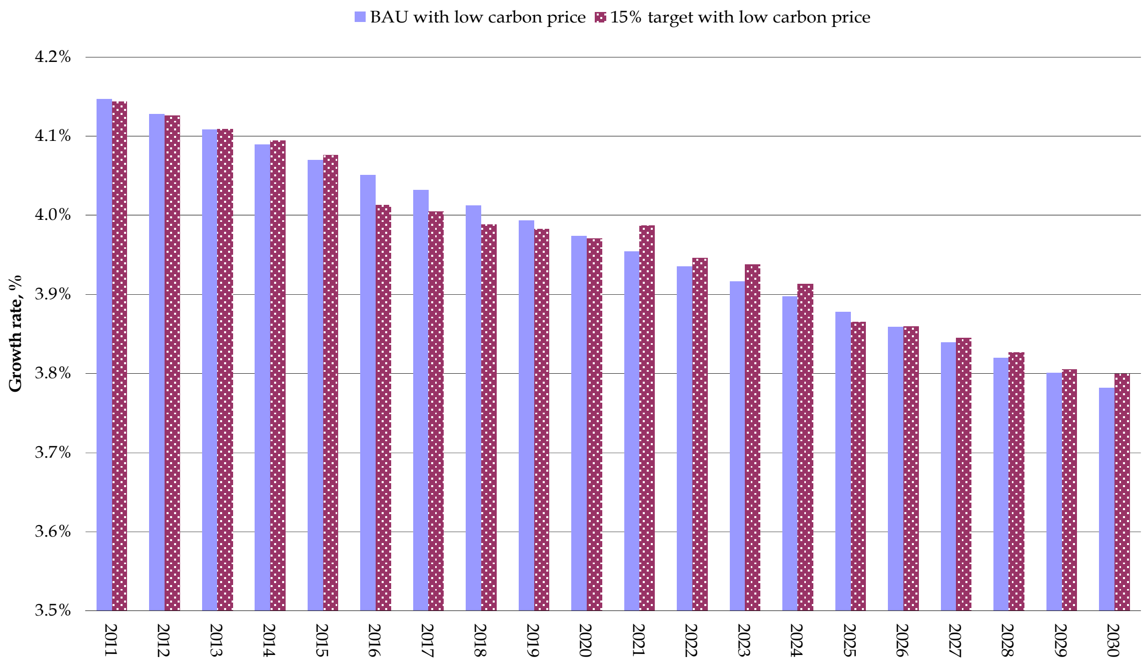


Figure 4-4: Change in GSP

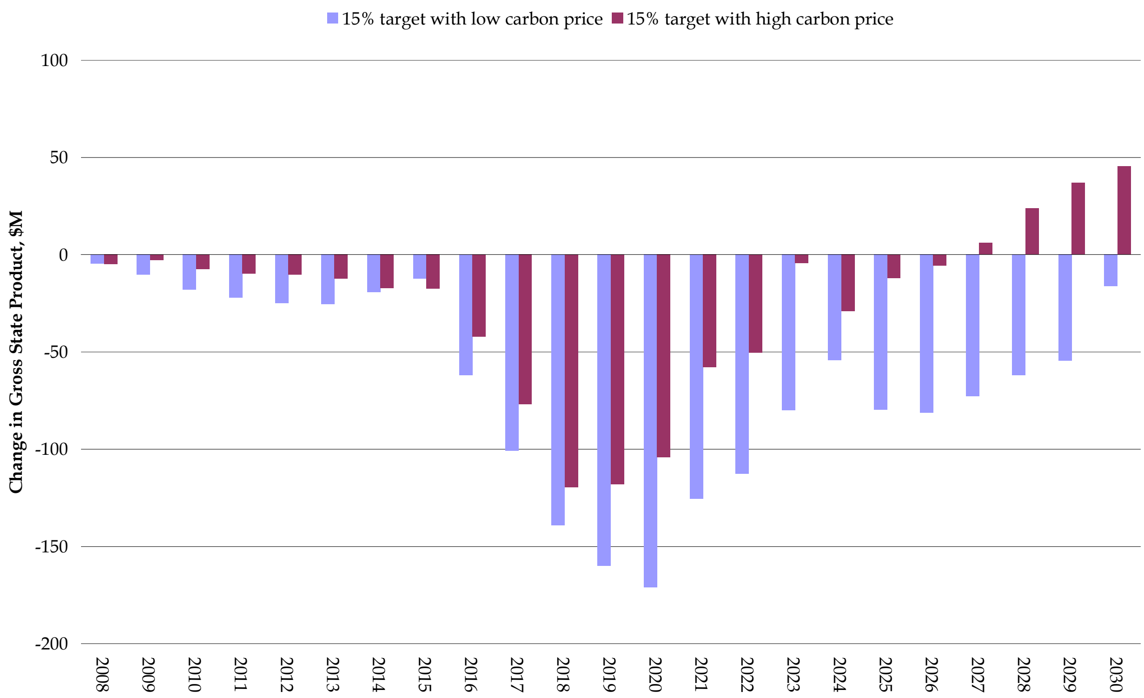


Table 4-2: Reductions in Western Australia GSP, 2020

	$M	% of GSP
15% low carbon price	-171	-0.11
15% high carbon price	-104	-0.07

Source: Analysis by CoPS.

Another measure of the welfare impact of the renewable energy target is the change in consumption (see Table 4-3)[19]. As a result of a 15% renewable energy target, the present value private consumption in Western Australia is expected to be lower by between $112 million to $317 million over the length of the measure. Although this is less than the fall in GSP, in proportional terms it is of equivalent magnitude. It appears that the major impact of the target would fall on private investment, with a slight gain in investment in electricity generation offset by falls in investment in other sectors of the Western Australian economy.

Aside from the conventional generation sector, the economic impact is realised broadly across the economy, and mostly in Perth. Impacts in regional areas are negligible.

[19] Changes in consumption can provide a better estimate of impacts on natioanl welfare because it excludes the impacts of transfers of income to foreign entities

Table 4-3: Present value of the annual change in GSP, consumption and investment in Western Australia

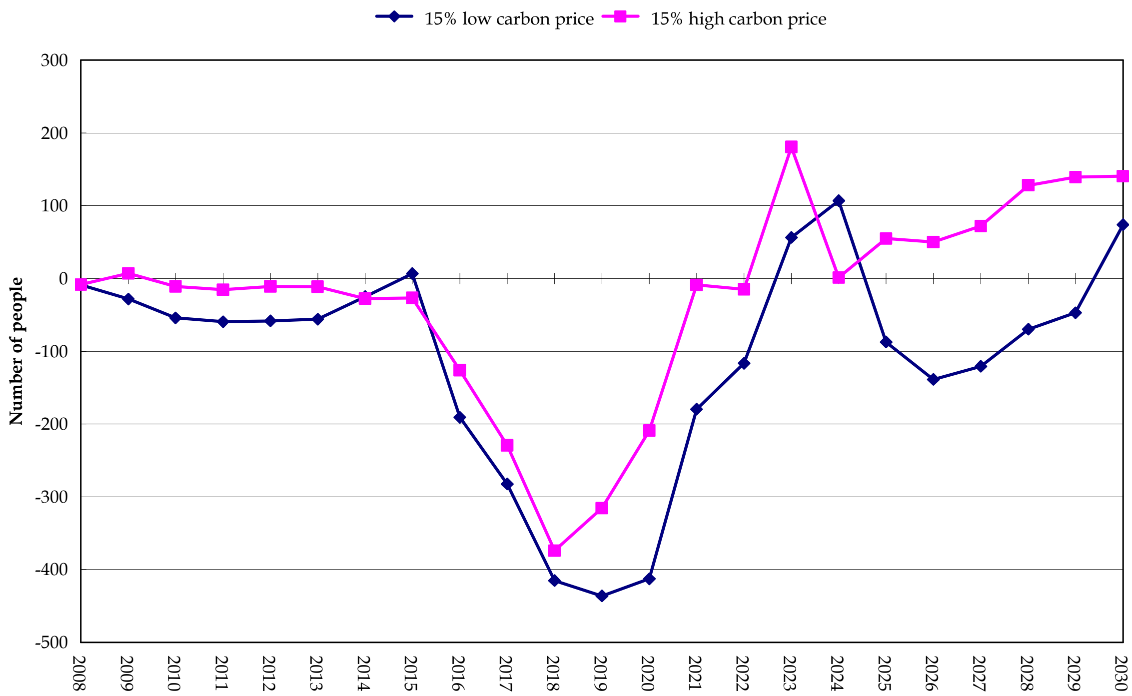
	GSP		Consumption		Investment	
	$M	% of total	$M	% of total	$M	% of total
15% low carbon price	-835	-0.028%	-317	-0.025%	-891	-0.092%
15% high carbon price	-296	-0.010%	-112	-0.009%	-716	-0.075%

Source: Analysis by CoPS. Present values calculated for the period 2007 to 2035 using a nominal discount rate of 5.9% converted into real terms using an inflation rate of 2.5%.

4.3 Employment

Employment is expected to grow more slowly as a result of the target. Over the study period, the number of full-time equivalent positions is less on average by about 111 positions for the low carbon scenario and 27 positions in the high carbon scenario. In both scenarios, the fall is greatest in the period from 2016 to 2021. The bulk of the impact is realised in the general economy sectors like business services and is driven by the higher electricity prices flowing through to the rest of the economy.

Figure 4-5: Change in employment compared with business-as-usual, full-time equivalents



Despite the lower level of employment, Figure 4-6 shows that employment is still expected to grow strongly with a renewable energy target.

Figure 4-6: Employment levels, full-time equivalents

4.4 Industry impacts

Table 4-4 shows the impact on the real value added by industry class. Two trends emerge from the estimates. Firstly, most industries experience a small fall in the value of output. The largest fall occurs for the fossil fuel based electricity industry, the coal industry and construction and business services industries. All other industries experience falls in the value of output of less than 0.1% over the study period. Secondly, the industries that gain value are those industries which are not liable under the measure (trade exposed energy intensive industries), as these experience a fall in wholesale energy prices. In particular, the other mineral ore and alumina industries expand with the target. As expected, the renewable energy industry also expands.

In general, there is a smaller impact in the high carbon scenario, because renewable energy generation is comparatively more competitive with higher carbon prices and hence the economic impact of the target is smaller.

Table 4-4: Present value of changes in industry output from 2007 to 2035

	15% low carbon price		15% high carbon price	
	$M change	% of total	$M change	% of total
Agriculture - animal	-2	0.0%	0	0.0%
Agriculture - other	-3	0.0%	0	0.0%
Forestry	0	0.0%	0	0.0%
Fishing	-2	0.0%	0	0.0%
Coal	-252	-5.4%	-254	-5.6%
Oil	-3	0.0%	0	0.0%
Gas	48	0.0%	58	0.0%
Iron ore	-11	0.0%	-1	0.0%
Other mineral ore	16	0.0%	31	0.0%
Other mining	-39	0.0%	-19	0.0%
Food products - animal	0	0.0%	0	0.0%
Food products - other	-3	0.0%	0	0.0%
Drink	-3	-0.1%	-1	0.0%
TCF	-1	0.0%	0	0.0%
Wood products	-5	-0.1%	-2	0.0%
Paper products	-3	0.0%	-1	0.0%
Manufacturing nec	-6	0.0%	-2	0.0%
Petroleum products	-1	0.0%	0	0.0%
Chemical prods. excl. petrol	12	0.1%	7	0.1%
Plastic and rubber products	-3	-0.1%	0	0.0%
Building prods (not cement & metal)	-2	0.0%	-1	0.0%
Cement	-3	-0.1%	-2	0.0%
Iron and steel	5	0.3%	3	0.1%
Alumina and aluminium	29	0.1%	22	0.1%
Other metal products	-8	-0.1%	-2	0.0%
Transport equipment	-6	-0.1%	-2	0.0%
Other equipment	-8	-0.1%	-3	0.0%
Electricity - coal	-371	-10.9%	-374	-11.5%
Electricity - gas	-45	-0.6%	-33	-0.4%
Electricity - Biomass	461	159.9%	447	151.8%
Electricity - Biogas	187	163.8%	183	157.9%
Electricity - Wind	307	163.8%	298	156.2%
Electricity supply	-48	-0.1%	8	0.0%
Urban gas distribution	7	0.2%	6	0.2%

	15% low carbon price		15% high carbon price	
	$M change	% of total	$M change	% of total
Water and sewerage services	-1	0.0%	2	0.0%
Construction services	-157	-0.1%	-118	-0.1%
Trade services	-67	0.0%	-36	0.0%
Accommodation and restaurants	-8	0.0%	-1	0.0%
Road transport services	-11	0.0%	-3	0.0%
Rail transport services	-6	0.0%	-4	0.0%
Water transport services	0	0.0%	0	0.0%
Air transport services	-4	0.0%	-1	0.0%
Other transport services	-10	0.0%	-2	0.0%
Communication services	-34	0.0%	-6	0.0%
Financial services	-29	0.0%	1	0.0%
Dwelling ownership	-28	0.0%	-15	0.0%
Business services	-132	0.0%	-45	0.0%
Public services	-19	0.0%	-4	0.0%
Other services	-13	0.0%	-5	0.0%
Private transport services	-11	0.0%	-6	0.0%

Source: Centre of Policy Studies.

5 POLICY IMPLICATIONS

Renewable energy is currently a more expensive form of generation than conventional fossil fuel generation. Although imposing a target will have a small impact on electricity prices and an even smaller impact on economic growth and employment, there is still an economic cost. However, there will also be benefits stemming from the target. The benefits tend to be either non-pecuniary (e.g. lower emissions of harmful air pollutants), or may not be realised until well into the future (e.g. lower renewable energy costs in the long-term). Renewable energy targets may also help in achieving long-term greenhouse gas abatement targets in the future at lower costs.

The conundrum is that the higher the target, the greater the benefits. However, the costs of the measure become less certain as the target increases. This suggests an incremental approach is warranted, with a wait and see attitude to determine if benefits and costs are in line with predictions.

5.1 Summary of impacts

The key impacts from the renewable energy targets are shown in Table 5-1. The main impact is that the delivered prices to customers increase, as a result of purchasing certificates to cover the cost of higher levels of renewable energy generation. However, even with a 20% target, retail prices are expected to increase at less than 2% on average above the increases incurred through emissions trading over the study period. The higher cost of renewable energy generation increases the cost of electricity generation, with additional capital and generation costs ranging from $500 million to $1,800 million over the study period. Economic growth and employment growth rates, although lower, still remain strong even with high renewable energy targets.

Despite these costs, the renewable energy targets also bring some benefits. For example, emissions of greenhouse gases from generation in Western Australia are reduced by between 14 Mt CO_2e to 42 Mt CO_2e. However, any greenhouse emissions savings as a result of the scheme will reduce the national emissions abatement task, for a given national greenhouse gas emissions target.

The results are sensitive to a number of key assumptions:

- Although the Western Australian government has committed to participating in a future national emissions trading scheme, the cost of carbon emissions as a result of this scheme is yet to be determined. The results in this study are based on a range of carbon prices. Sensitivity analysis is also undertaken using a zero carbon price assumption, in light of the possibility that carbon pricing is not introduced in the SWIS at any stage in the future.

- Electricity demand growth could be higher or lower than assumed in this study. If a set target in GWh is used, the main impact of higher or lower rates of growth will be on the impacts on prices and incumbent generators.
- Less competitive bidding in the STEM may lead to different price impacts than estimated in this study, namely higher prices in the electricity market, increasing the comparative competitiveness of renewable energy technologies and reducing the cost and economic impact of targets.
- Impacts on the transmission system from high levels of intermittent generation may lead to higher system or ancillary service costs, increasing the cost and economic impact of targets.
- The cost of renewable energy generation in the future. This is particularly the case for targets greater than 15%. However, any adverse impact from higher than expected costs can be managed by imposing a cap on the certificate price, a mechanism that has been adopted for similar schemes in other states. The mix of renewable energy generation projects that come forward in response to a target is also likely to be sensitive to changes in the costs of renewable energy technologies.

Table 5-1: Summary of impacts

	10%	15%	20%
Low carbon price			
Impacts			
Certificate price, $/certificate	20.1	24.7	25.1
Wholesale electricity price increase, %	0.0%	1.5%	3.2%
Retail price increase, %	-0.1%	0.7%	1.7%
Resource costs, $M	158	623	818
GDP costs, $M	na	835	na
Benefits			
Abatement of greenhouse gas in the SWIS, Mt CO_2e	14	30	42
Investment in renewable energy generation, $M	477	1,054	1,496
High carbon price			
Impacts			
Certificate price, $/certificate	12.0	17.1	17.3
Wholesale electricity price increase, %	-0.4%	1.0%	1.3%
Retail price increase, %	-0.4%	0.5%	0.7%
Resource costs, $M	463	901	1,156
GDP costs, $M	na	296	na
Benefits			
Abatement of greenhouse gas in the SWIS, Mt CO_2e	14	27	41
Investment in renewable energy generation, $M	688	1,198	1,740

Source: Analysis by MMA and CoPS. The abbreviation "na" denotes not available.

5.2 Policy implications

Implications for policy arising from this study include:

- Because of the uncertainty around the availability of renewable energy projects, less confidence can be placed on the results of targets higher than 15%.
- The uncertainty in the costs and benefits implies that some review should be endorsed to ensure that the scheme works to achieve its objectives.
- A penalty should be imposed both to limit liabilities and to force renewable energy generators to reduce costs (since this is one of the main objectives of the scheme). A declining penalty rate will encourage renewable energy generators to pass through cost reductions and any comparative advantage gained as a result of the introduction of carbon trading. Penalties of around $40/MWh declining by around 3% per annum should be sufficient to secure the required amount of renewable energy generation.
- The impact on incumbent generators may need to be managed. The analysis indicates that the bulk of any drop in profitability occurs early on in the scheme. This could be managed by a slower ramp up to the ultimate target.
- An emerging issue is the high number of schemes that retailers have to comply with. There is likely to be pressure to merge the state based renewable energy targets some time in the future. New South Wales is aiming for a 15% target by 2020, leading to an additional 7,000 GWh of renewable energy generation in that state. The Victorian scheme aims for 10% by 2016, translating into an additional 3,200 GWh of renewable energy generation. Taking the midpoint target examined in this study, a 15% target by 2020 in Western Australia translates into a target level of new renewable energy generation of around 2,400 GWh. Mandatory national targets around the 15% target level will merge more easily into any future national scheme than higher targets. Furthermore, the low net cost of renewable energy generation in Western Australia (due to higher electricity prices), should mean that renewable energy generation in this state will be highly competitive to meet any national target.

APPENDIX A DETAILED ASSUMPTIONS USED IN THE ELECTRICITY MARKET MODEL

A.1 Introduction

The market simulations take into account the following parameters:

- Regional and temporal demand forecasts.
- Generating plant performance.
- Timing of new generation including embedded generation.
- Existing interconnection limits.
- Potential for interconnection development.

The following sections summarise the major market assumptions and methods utilised in the forecasts.

A.2 Software platform

The wholesale market price forecasts are developed utilising Strategist probabilistic market modelling software, licensed from New Energy Associates. Strategist represents the major thermal, hydro and pumped storage resources as well as the interconnections between electrical supply regions. MMA partitions the SWIS into three zones (south west, goldfields and north west zones), to better model the impact of transmission constraints and marginal losses. These constraints and marginal losses are projected into the future based on past trends.

The simplifications in bidding structures and the way Strategist represents inter-regional trading, result in slight under-estimation of the expected prices because:

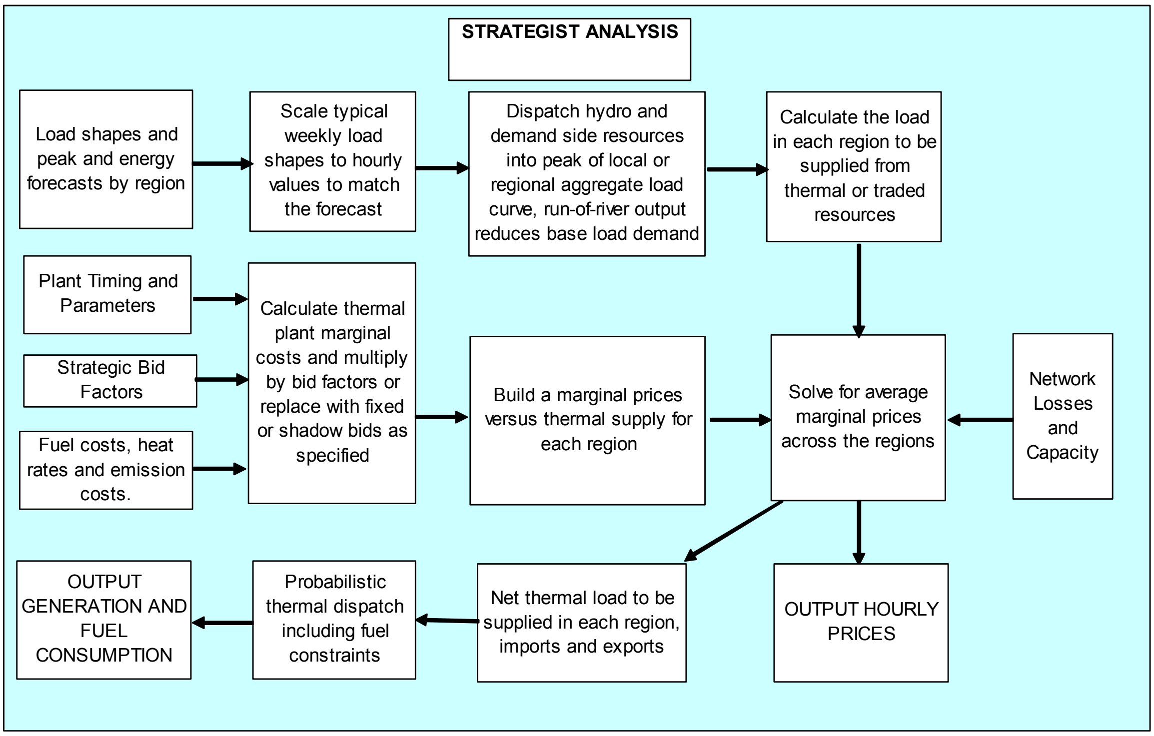
- All the dynamics of bid gaming over the possible range of peak load variation and supply conditions are not fully represented.
- Extreme peak demands and the associated gaming opportunities are not fully weighted. These uncertainties are highly skewed and provide the potential for very high prices outcomes with quite low probability under unusual demand and network conditions.
- Marginal prices between regions are averaged for the purposes of estimating inter-regional trading, resulting in a tendency to under-estimate the dispatch of some intermediate and base load plants in exporting regions.

However, overall corrections can be made where these measures are important and in any case, the error in modelling is comparable to the uncertainty arising from other variable market factors, such as contract position and medium term bidding strategies of portfolios. Overall, the results presented in this report represent a conservative view, applicable for long-term investment in generation capacity.

A.3 Methodology

Average hourly pool prices are determined within Strategist based on thermal plant bids derived from marginal costs or entered directly. The internal Strategist methodology is represented in Figure A-1 and the MMA modelling procedures for determining timing of generation and transmission, and bid factors are presented in Figure A-2.

Figure A-1: Strategist analysis flowchart

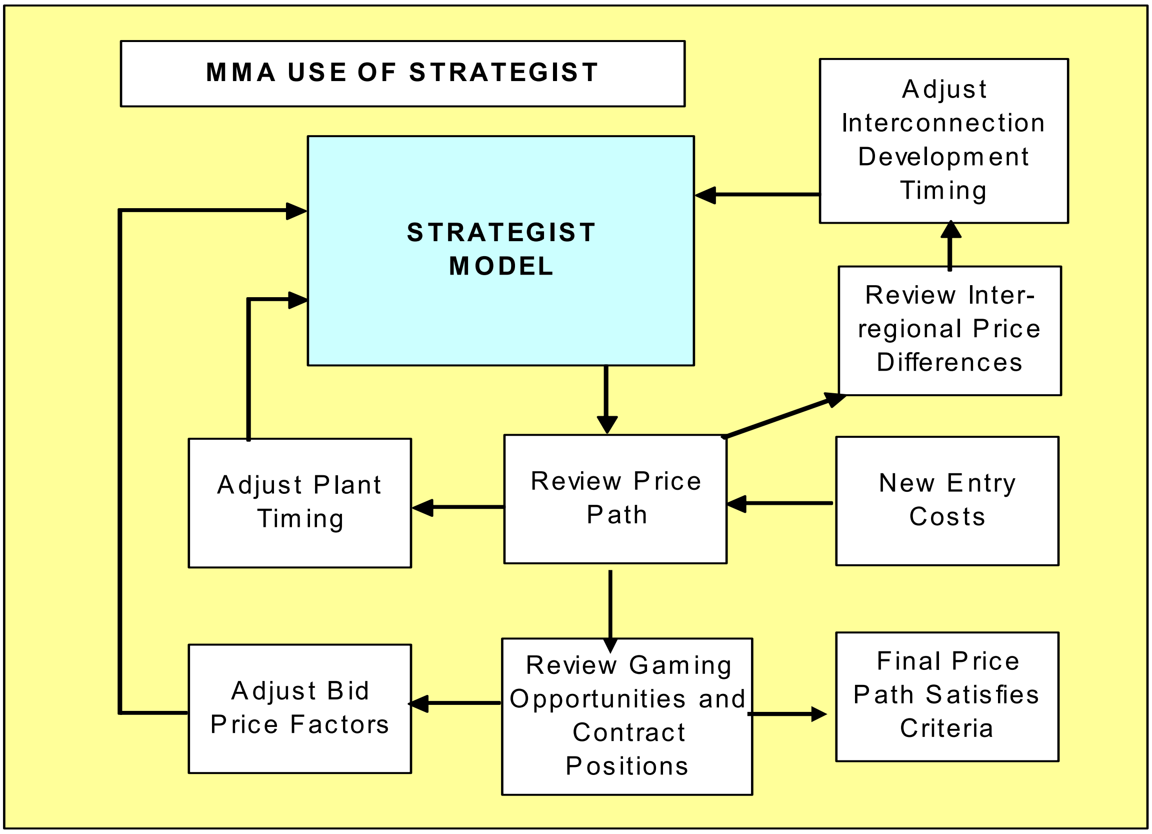


Strategist generates average hourly marginal prices for each hour of a typical week, for each month of the year, at each of the regional reference nodes[20], having regard to all possible thermal plant failure states and their probabilities. The prices are solved across the regions of the SWIS having regard to inter-regional loss functions and capacity constraints. Failure of transmission links is not represented, although capacity reductions are included based on historical chronological patterns.

Bids are generally formulated as multiples of marginal cost and are varied above unity to represent the impact of contract positions and the price support provided by dominant market participants. Some cogeneration plants are bid below unity to represent the value of the steam supply which is not included in the power plant model.

20 In MMA's model of the SWIS, we assume three regional nodes to reflect major transmission constraints (South West Region, with a regional reference node at Muja, Goldfileds Region and North County region).

Figure A-2: MMA Strategist modelling procedures



A.4 SWIS assumptions

The South West Interconnected System (SWIS) covers the electricity grid in the south west corner of Western Australia, from Geraldton in the north to Kalgoorlie in the east. It covers the major load centres of Perth, Kwinana Industrial Zone, Fremantle and Kalgoorlie. Verve Energy, a publicly owned company, is the dominant generator, competing largely against some smaller independent power producers and surplus from independent cogeneration plant.

In this section, we present the key assumptions underpinning MMA's market model of the SWIS.

A.4.1 Trading arrangements

Under the reforms being implemented, the wholesale market for electricity in the SWIS has been restructured into:

- An energy trading market, which is an extension of the existing bilateral contract arrangements.
- An ancillary services market to trade spinning reserve and other services to ensure supply reliability and quality.

The SWIS is relatively small, and a large proportion of the electricity demand is from mining and industrial use, which is supplied under long-term contracts. Considering

these features, the Electricity Reform Task Force evaluation determined that it would be most appropriate for a bilateral contracts market to continue to underpin the SWIS, with a residual day ahead trading market (called the STEM). This residual trading market is anticipated to allow contract participants to trade out any imbalances, and also allow small generators to compete where they would otherwise not be able to, due to their inability to secure contracts.

Market participants will have the option of either entering into bilateral contracts or trading in the STEM.

The ancillary services market is initially going to be the responsibility of system management. System management will be required to determine the least cost supplies to satisfy the system security requirements. Both independent generators and state generation could be ancillary reserve providers, but at least initially, it is envisioned that the state generator will need to provide all spinning reserve under contract with system management.

All market participants will need to pay for the ancillary services. In our SWIS model, we assume that there is a market for trading spinning reserve. Providers receive revenue for this service, and the cost is allocated to all generators above 115 MW, with the largest cost disproportionately allocated to the largest unit.

A.4.2 Market rules

The STEM commenced operation in July 2006. Under the market rules:

- All generation plants will be self-scheduled to meet their bilateral and STEM contract positions, which means that they determine when to be committed and de-committed.
- Bilateral contracts will be self-dispatched, although system management may override this dispatch to maintain system security.
- Supply and demand will be balanced in the STEM by centrally determining the residual dispatch requirements.
- A single market-clearing price will exist in the STEM. This price will exclude the effect of network congestion.
- Maximum prices in the STEM will be capped at the SRMC of gas and distillate peaking plant.

In the MMA model of the SWIS, we ignore bilateral contracts and allow all generation to be traded in the market. The reasoning behind this is that the contract quantities and prices will be very similar to the market dispatch – otherwise one or other party would not be willing to enter the contract. Admittedly, contracts provide benefits from hedging that will not be reflected in the trading market. However, in the long run, the differences between contracts and the trading market will be minimal.

It has been assumed that the Value of Lost Load (VOLL) is $10,000.

A.4.3 Structure of generation

The state generator, Verve Energy, was disaggregated vertically from the rest of Western Power but not horizontally. Horizontal disaggregation may still be deemed necessary if it is considered that a single state generator has excessive market power. In our model, we assume that Verve Energy is one generating entity.

To encourage competition, Verve Energy will not automatically be allowed to build new plant to replace its old or inefficient plant. Our assumptions for analysis are:

- To allow a new base load plant to replace Kwinana A in December 2008, with ownership by Newgen, an IPP with a long-term contract for the output of the station.
- To allow Verve Energy to bid for new entry generation, as long as its overall generation capacity does not exceed 3,000 MW.

A.4.4 Demand assumptions

Three key demand parameters are used in the model:

- Peak demand at busbar.
- Energy requirements.
- Load profiles.

Energy consumption forecasts for the SWIS are provided by CoPS. The forecast energy consumption is split between the three regions to create MMA's projections for electricity sent out. The annual compound growth rate for total electricity demand in the SWIS is around 3.5% (or 3.1% if including the Alcoa loads).

Projections of the summer and winter peak demand at generator busbar are derived from forecasts of load factors provided by the IMO and applying these load factors to energy consumption data provided by CoPS to get summer peak demands.

Peak demand for each month is calculated based on the forecast summer peak demand and historical load profiles.

Using data provided by Western Power and the IMO, MMA derived a SWIS load profile. This data was normalised to the peak value for 2004/2005 and then modified to ensure consistency with energy sales and load factors. The load growth algorithm in our simulation model then used this historical load profile to forecast demand for the entire planning horizon, ensuring consistency with the annual peak and energy sales assumptions for the study period. This implies that we are assuming that the monthly pattern of energy sales and peak demand remains constant during the forecast period.

A.4.5 Generation assumptions – existing units

Verve Energy

Verve Energy has eleven power stations operating in the SWIS, as shown in Table A-1. The Muja stations operate as base load stations with capacity factors of 70 to 95%. The Kwinana steam plants and the Mungarra gas turbine operate as intermediate plants with capacity factors of about 40%, while the Pinjar gas turbines operate as peaking plant with 10 to 20% capacity factor. Cogeneration plants are also assumed as must-run plants, due to steam off-take requirements.

The South West Cogeneration Joint Venture is comprised of 50% Origin Energy and 50% Verve Energy. Approximately 30 MW of electricity in supplied to the alumina refinery, with the remainder being supplied to domestic customers via the SWIS. Steam from the cogeneration plant is used in the alumina refinery process and also in its own station. This is a 130 MW coal-fired plant owned by Worsley Alumina.

The Kwinana A and C stations are modelled to be able to burn both coal and gas up until July 2004, and gas only after that time.

The physical characteristics and the fixed and variable operating and maintenance costs for each plant are shown in Table A-1 and Table A-2.

Table A-1: Power plant operating assumptions

Station	Type	Capacity in summer peak, MW sent out	Fuel	Maintenance (%)	Forced outage (%)	Heat rate[2] GJ/MWh
Albany	Wind turbine	12 x 1.8	renew.	-	3	-
Collie A	Steam	304	coal	6	2	10.0
Muja A/B	Steam	4 x 50.5	coal	7	6	12.5
C	Steam	2 x 185.5	coal	4	4	11.0
D	Steam	2 x 185.5	coal	4	3	10.5
Kwinana A	Steam	2 x 103.5	coal, gas	5	5	11.0
B	Steam	2 x 96.5	gas, oil	10	5	11.0
C	Steam	2 x 180.5	coal, gas	4	6	10.8
GT	Gas turbine	16	gas, dist	2	3	15.5
Pinjar A,B	Gas turbine	6 x 29	gas	6	3	13.5
C	Gas turbine	2 x 91.5	gas	6	3	12.5
D	Gas turbine	123	gas	6	3	12.5
Mungarra	Gas turbine	3 x 29	gas	6	3	13.5
Geraldton	Gas turbine	16	gas, dist	2	3	15.5
Kalgoorlie	Gas turbine	48	dist	2	3	14.5
Worsley[1]	Cogeneration	70	gas	4	2	8.0
Tiwest	Cogeneration	29	gas	6	3	9.0

1 Muja A/B is assumed to close in 2006/07.

2 South West Cogeneration Venture – 120 MW nameplate, 50% Verve Energy owned.

3 Heat rates at maximum capacity. Heat rates are on a sent out basis (that is, GJ of energy delivered per unit of electricity sent out in MWh). Heat rates have been adjusted to be based on the higher heating value of fuels.

Source: Western Power, *Annual Report, 2004-2005*, Perth (and previous issues); estimates of maintenance time, unforeseen outages and heat rates for OCGTs and CCGTs are based on information supplied by General Electric and the IEA.

Table A-2: Fixed and variable operating costs

Station	Unit	Fixed costs ($000s/year)	Variable costs ($/MWh)
Albany	0	0	
Collie	A	5,000	4.00
Muja	A/B	5,500	8.50
	C	5,500	5.50
	D	5,500	5.00
Kwinana	A	6,500	8.00
	B	4,000	8.00
	C	8,000	7.00
	GT	250	9.00
Pinjar	A,B	500	4.00
	C	1,500	4.50
	D	1,500	4.50
Mungarra		500	4.00
Geraldton		250	5.00
Kalgoorlie		250	5.00
Wellington		0	5.00
Worsley		1,500	4.00
Tiwest		500	4.00

Source: Derived by MMA to match operating and maintenance cost data contained in Western Power annual reports.

Other generators

Private generating capacity, including major cogeneration, is detailed in Table A-3. The capacity is mostly comprised of gas-fired generation. There has been a large increase in privately-run generating capacity, due to substantial falls in gas costs and the gradual deregulation of the generation sector. Over the 1996-1997 period, some 324 MW of privately-owned generation capacity was commissioned at Kwinana and the Goldfields.

The 116 MW BP/Mission Energy cogeneration project commenced operation in 1996. The BP host takes 40 MW of power, with the remaining 74 MW of power being taken by Western Power under a long-term take or pay agreement. About 3 PJ pa of fuel for the 40 MW portion of output will be natural gas purchased directly from the NWSJV, and other inputs will be refinery gas.

Power generation from gas in the Goldfields commenced in 1996. Southern Cross Power generates from four 38 MW LM6000 gas turbine stations for its Mount Keith, Leinster, Kambalda nickel mines and its Kalgoorlie nickel smelter. The stations are expected to use about 14 PJ of gas pa (37 TJ/d), sourced from the East Spar field. Goldfields Power has constructed 110 MW of capacity (3 x LM6000 gas turbines) east of Kalgoorlie to supply the SuperPit, Kaltails and Jubilee gold projects.

Table A-3: Generating plants over 10 MW capacity in the SWIS

Company	Fuel	Capacity in summer peak, MW sent out	Maintenance (%)	Forced outage (%)	Heat rate GJ/MWh
Alcoa	gas	212	3.8	2	12.0
BP/Mission	gas	100	3.8	2	8.0
Southern Cross	gas	4 x 30	3.8	4	11.7, 12.7
Goldfields Power	gas	3 x 30	3.8	1	9.5
Worsley	gas	27	3.8	2	8.0

Source: Capacity data from publications published by the WA Office of Energy, MMA analysis based on typical equipment specifications published in Gas Turbine World.

Most of the plants are located near major industrial loads. Some wheeling of power is also undertaken. BP/Mission's cogeneration plant at Kwinana supplies electricity to Western Power. Consequently, this cogeneration plant is treated as a must-run unit. Other units treated this way include Tiwest and Worsley. Both Southern Cross Power and Goldfield Power's plant in Kalgoorlie, wheel power to other industrials within the SWIS.

A.4.6 Derating of units

The capacity of the gas turbines is affected by temperatures at the inlet of compressors. The hotter the temperature at the inlet, the lower the capacity. The average monthly deratings, as a percentage of rated capacity are shown in Table A-4. The same deratings are applied to all OCGTs, except for the Alcoa units. The Alcoa units are derated to a lesser degree, as are CCGTs and cogeneration plant. Coal units are similarly derated over the warmer months, though not as much.

Table A-4: Monthly deratings – percent of maximum capacity

	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
OCGT	0	0	10	11	13	16	18	18	16	13	11	0
CCGT	0	0	7	7	9	11	12	12	11	9	7	0
Coal	0	0	0	0	3	4	5	5	4	0	0	0

Source: Based on data provided by NEMMCO for comparable units and aggregate data published by the WA Independent Market Operator.

Collie 1 is also derated every night to two thirds of its normal operating capacity. This is to reduce the size of the spinning reserve requirement that must be covered by other running units. The provision must be at least as large as the largest unit operating. Therefore, if the coal unit reduces generation, other units may be able to shut down overnight, as they will no longer be needed to provide reserve.

A.4.7 New thermal units

To meet the anticipated growth in demand in the SWIS beyond 2008, additional generation plants will be required. Furthermore, Verve Energy has committed to retiring old and inefficient units – specifically Kwinana B in 2003, Kwinana A in 2008, and Muja A/B in 2007 – and these capacities will need to be replaced.

The additional capacity required could be met from a number of generation options:

- Open cycle gas turbines (OCGTs), which have low capital costs but require a premium fuel.
- Combined cycle gas turbines (CCGTs), which have lower operating costs than OCGTs, due to their high efficiency.
- Coal-fired plant, which has the highest capital cost but low operating costs due to the competitive price of coal. These are likely to be similar to the 200 MW units proposed by Griffin Energy (the Bluewater Project).
- Cogeneration, which is efficient like CCGTs but also has an additional benefit from the steam supply.
- New CCGTs at Cockburn, owned and operated by Verve Energy.

One of the Cockburn CCGTs is already operating. A further 240 MW Cockburn CCGT was intended to replace the Kwinana A plants by December 2005, but has now been delayed. In our model, only one Cockburn unit is assumed to be commissioned, as there are restrictions on the amount of capacity that state generation can maintain over the medium term.

It is assumed that the base load Wambo CCGT is commissioned by the end of 2008. After this date, new plant selection is based on least cost options.

The assumed physical parameters and costs for the new plant options are shown in Table A-5 and Table A-6.

Table A-5: Assumptions on heat rate, capacity and technology of new plant

New Plant	Technology	HHV Heat rate GJ/MWh	Gross Capacity, MW nominal	Capacity in summer peak, MW sent out	Fuel
Collie 2	Supercritical Coal-fired	9.3	325 MW	292	Coal
Small coal (Bluewaters)	Subcritical Coal-fired	10.5	200 MW	180	Coal
OCGT	Open-cycle	12.2	120 MW	95	Gas
CCGT	Combined cycle	7.7	240 MW	202	Gas
Alinta	Cogeneration	6.0	140 MW	134	Gas
Cockburn	Combined cycle	7.7	240 MW	202	Gas

Note: Alinta cogeneration plant's heat rate includes savings in gas not used to raise process steam

Table A-6: Outage and costs assumptions for new plant

New Plant	Maintenance (%)	Forced outage (%)	Capex ($/kW)	Fixed costs ($000s/year)	Variable O&M costs ($/MWh)
Coal-fired plant	4.0	2	1,400 – 1,600	9,300	4
OCGT	3.8	3	700	1,300	1
New CCGT	3.8	2	1050	3,000	7
Alinta Cogen	3.8	2	900 - 950	5,400	1
Cockburn 2	3.8	2	1,250	3,000	7

Long-term levelised costs for new generation are estimated based on pre-tax costs and using a real discount rate of 9% pa. The value of 9% is based on current rates of return to equity (13%) and debt (7%), and a standard debt to equity ratio.

A.4.8 New renewable energy generation

The wind farms at Walkaway and Emu Downs that commenced operation in 2006/2007 are assumed to have a capacity factor of around 38% and to operate throughout the study period. Co-firing at Muja at 5% output for one unit is also assumed to continue during the study period.

A.4.9 Fuel assumptions

In this report, all assumptions on fuel usage and unit costs are based on the higher heating value (or gross specific energy) for each fuel, in line with accepted practices in Australia.

Coal prices

Coal supplied by Wesfarmers Coal under current take-or-pay contracts is assumed to have a higher heating value of 19.8 GJ/t on average. Coal supplied by Griffin Coal is assumed to have a higher heating value of 19.3 GJ/t on average, as does incremental coal assumed to be sourced from new mines. The levels of current take-or-pay contracts for coal used in the model are as shown in Table A-7.

Table A-7: Coal contract quantity assumptions

FY ending	Griffin Coal (Mtpa)	Wesfarmers Coal (Mtpa)
2007	1.5	2.0
2008	1.5	2.0
2009	1.5	2.0
2010	1.5	2.0
2011 to 2030	-	3.5

Source: MMA assumptions derived from data contained in reports published by Western Power.

Griffin Coal Mining and Western Power also supply coal to Worsley. Worsley's coal-fired plant requires 800 kt of coal per year.

Coal prices for the contract coal are assumed to be $51/tonne until 2010. Incremental coal used over and above the contract commitments will be sold at the new coal price.

In the MMA model, new coal prices and contract coal after 2010 are assumed to be $40/t on a delivered basis for 19.3 GJ/t specific heat. Prices remain at this level in real terms for the period of the analysis, based on the assumption that substantially higher prices would either breach long-term import parity prices for imported coal, or would mean that coal would be uncompetitive with natural gas as a fuel in generation and fuel combustion markets.

The Kwinana A and C stations are modelled to be able to only use gas from 2007 onwards.

Gas prices

Delivered gas prices consist of a component for gas supplied under the North West Shelf Joint Venture (NWSJV) contract and a transport component.

Three types of gas are represented in the SWIS model:

- gold gas, used by the stations in the Goldfields region
- existing gas used by existing plants in the Perth region prior to 2007 when a new gas contract starts
- new gas, used by all other gas stations in the system.

MMA assumes that new gas supply will be priced at $3.50/GJ (at well head) in 2005 dollars, with the price escalating at 100% of the CPI increase. The transport charge is $1.10/GJ, escalating at 75% of CPI.

All stations owned by Goldfields Power and Southern Cross Power are modelled to use Gold gas. The estimated 2005 price of this gas is \$3.50/GJ (at well head).

There is assumed to be no limit on gas transmission – additional capacity will be added as required. The gas transmission charge is assumed to be \$3/GJ for gas supplied to the Goldfields region, reflecting the distances gas needs to be transmitted in this region, deflating at 75% of the CPI.

APPENDIX B COST TRENDS FOR RENEWABLE ENERGY GENERATION

Unless otherwise stated, assumptions regarding the cost reduction opportunities have only been applied to the capital cost component of renewable energy projects, since this is the cost component that is most frequently discussed in the literature. This should be a reasonable simplification, as capital costs typically constitute by far the largest component in the overall costs of renewable energy projects, unlike non-renewable energy generation projects.

MMA's renewable energy generation cost curves have been divided into three periods, with different rates of capital cost reductions applied to each period.

1. 2005 to 2010: Cost reduction opportunities as predicted by the IEA and World Resources Institute.
2. 2011 to 2025: Depending on the technology, cost reduction opportunities during this time are based on a combination of published predictions and MMA's assessment of likely trends.
3. 2026 to 2030: This is the most difficult period to forecast, given the scarcity of long-term cost predictions. Rates of capital cost reduction during this period are based on the notion that cost reduction opportunities for most technologies are likely to reduce as the benefits from increases in installed capacity and local expertise will have been largely exhausted by this time.

Unless otherwise stated, the assumed rate of capital cost reduction for each technology is largely based on IEA predictions[21].

Table B-1: Capital cost reduction factors (% per annum)

Technology	2005-2010	2011-2025	2026-2050
Solar PV	5.0%	4.0%	2.0%
Biomass	2.5%	2.0%	0.5%
Geothermal	4.0%	3.5%	2.0%
Wind	3.0%	2.0%	0.8%
Wave	5.0%	4.0%	4.0%

Generation costs for wind farms in 2005 are based on MMA's database of RE projects in Western Australia. Capital cost reductions to 2010 are assumed to be similar to the average global value calculated from IEA's 2003 estimates (around 3.0% per annum)[22]. From 2011 to 2025, the rate of decline in capital costs is assumed to decrease to around

[21] International Energy Agency (2003), *Renewables for Power Generation: Status & Prospects*, Paris, France.

[22] International Energy Agency (2003), *Renewables for Power Generation: Status & Prospects*. Derived from investment cost data on p.165.

70% of the pre-2010 value, or about 2.0% per annum. By 2026, further opportunities for capital cost reductions are expected to be quite limited, hence the annual cost reduction is reduced to 0.8% per annum.

It is expected that improvements in wind turbine design and technology will lead to slight increases in capacity factor. However, it is possible that higher potential capacity factors resulting from technological improvements may eventually be offset by site limitations. As the level of installed wind capacity in Australia increases, it is likely that new wind farms may need to be located in areas with less than ideal wind regimes, thereby lowering achievable capacity factors[23]. It has therefore been assumed that average capacity factors will increase linearly by two percentage points by 2020. However, from 2021 onwards, siting issues are expected to completely eliminate any further potential for increases in average capacity factors.

Table B-2: Parameter values for wind energy

Parameter	Units	Low cost	Medium cost	High cost	Change from 2005 to 2030
Size	MW	115.5	115.5	115.5	Unchanged
Life	Years	25	25	25	Unchanged
Real pretax WACC	%	9.0%	9.0%	9.0%	Unchanged
Capacity factor		0.33	0.33	0.33	Increase by 2% points from 2005 to 2020 and does not increase further after this date.
Capital cost 2005	$/kW	1,350	1,700	2,050	Unchanged
Interest during construction	%	7.0%	7.0%	7.0%	Unchanged
Capital cost reduction	%	2.8%	2.8%	2.8%	Reducing over time
Fuel costs	$/MWh	0.0	0.0	0.0	Unchanged
O&M costs	$/MWh	5.0	5.0	5.0	Unchanged
Ancillary service costs	$/MWh	5.0	5.0	5.0	Unchanged
Transmission costs	$/kW	100	100	100	Unchanged

23 AusWEA (2004),*Cost Covergence of Wind Power and Conventional Generation in Australia*, Melbourne.

For biomass projects, 2005 cost estimates are primarily based on a recent report published by the Rural Industries Research and Development Corporation[24].

WACC is assumed to be slightly higher than some of the other renewable energy technologies (one percentage point higher) to account for biomass fuel supply risk. O&M costs are assumed to vary from $8.5/MWh to $15.5/MWh.

Given the difficulty in producing representative estimates of cost reductions for the large range of plant types that fall under the umbrella term of biomass, the capital cost reductions used in this study are based on the average IEA value.

Biomass plants are the only renewable energy plants that are likely to experience significant fuel costs. Furthermore, the magnitude of fuel costs is likely to vary substantially for different types of biomass applications (for example, fuel costs in landfill gas applications could be expected to be close to zero, whereas for plants using purpose grown short cycle tree plantations, fuel costs are likely to be very high - potentially as high as $100/MWh or more[24]). The biomass costs in this analysis are based on the assumption that the biomass fuel is a by-product of another process (for example, bagasse from sugar cane harvesting), and the fuel cost is therefore low enough for biomass plants to be competitive with other renewable energy technologies such as wind.

Table B 1: Parameter values for biomass projects

Parameter	Units	Low cost	Medium cost	High cost	Change from 2005 to 2050
Size	MW	20.0	20.0	20.0	Unchanged
Life	Years	15	15	15	Unchanged
Real pretax WACC	%	10.0%	10.0%	10.0%	Unchanged
Annual capacity factor		0.80	0.80	0.80	Increase from 80% in 2005 to 85% in 2020 and remains constant.
Capital cost 2005	$/kW	1500	2000	2500	Unchanged
Interest during construction	%	7.0%	7.0%	7.0%	Unchanged
Capital cost reduction	%	2.8%	2.8%	2.8%	Reducing over time
Fuel costs	$/MWh	10.0	15.0	20.0	Unchanged
O&M costs	$/MWh	8.5	12.0	15.5	Unchanged
Ancillary service costs	$/MWh	0.0	0.0	0.0	Unchanged
Transmission costs	$/kW	100	100	100	Unchanged

24 Stucley, C. R., Schuck, S. M., Sims, R.E.H, Larsen, P.L., Turvey, N.D. and Marino, B.E. 2004. *Biomass energy production in Australia: status, costs and opportunities for major technologies, A report for the Joint Venture Agroforestry Program (in conjunction with the Australian Greenhouse Office)*, ACT.

APPENDIX C SENSITIVITY ANALYSIS – NO CARBON PRICING

In this appendix, results are reported for a scenario which compares the cost of a renewable energy target when there is no emission trading scheme assumed.

Renewable energy certificates in the Western Australian scheme remain at around $30/certificate to $50/certificate in the absence of carbon pricing (Figure C-1).

Figure C-1: WAREC prices (no carbon price)

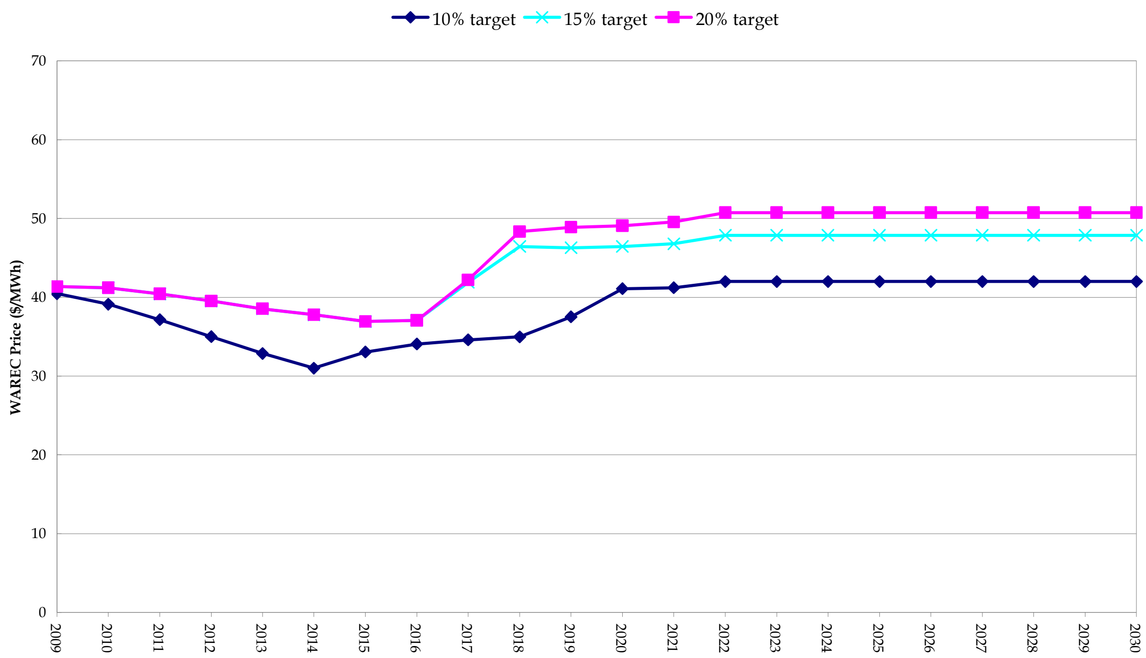
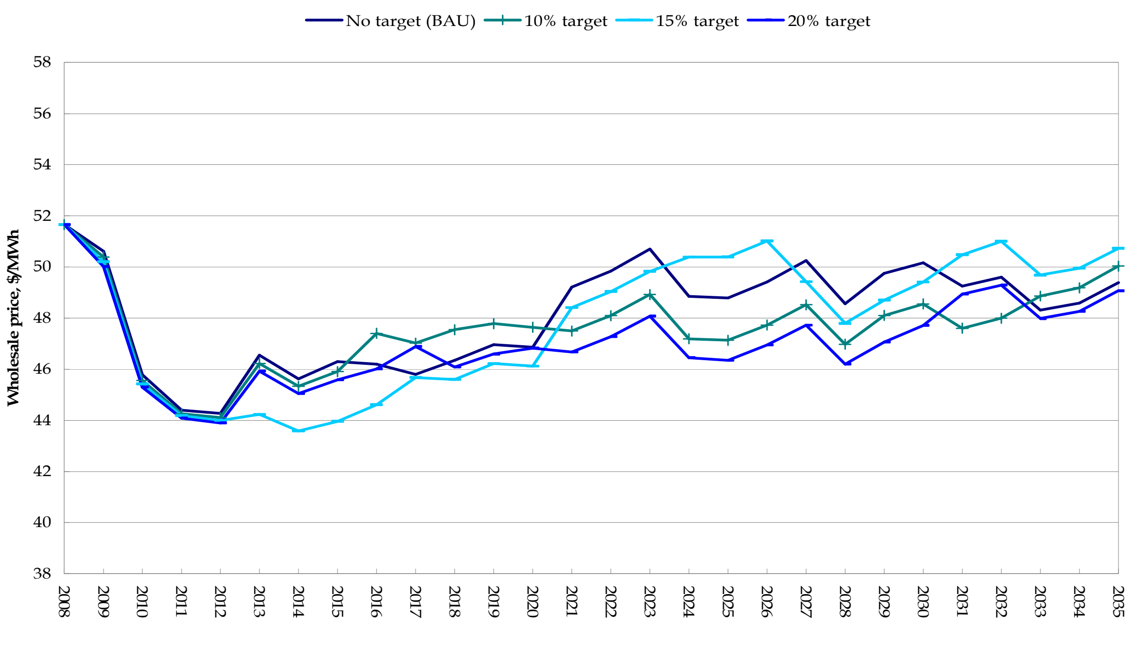


Figure C- 2: Wholesale prices (no carbon price)



Consequently, the renewable energy premium is larger. Retail price impacts, including any impact on wholesale electricity market prices (see Figure C-2), are shown in Table C-1. On average, the premium is equivalent to an electricity bill increase of $7 to $24 per annum for residential consumers, from now until the end of the scheme (Table C-2).

The resource costs of the target are about the same without carbon pricing. Small differences are due to trade-off differences in timing of new renewable energy generation (which tends to be earlier the higher the carbon price) and the cost savings from deferring new fossil fuel units (which tend to be lower the higher the carbon price). Estimates of the present value of additional resource costs are:

- $164 million for a 10% target.
- $399 million for a 15% target.
- $612 million for a 20% target.

The estimates of resource costs represent about 1% to 3% of the present value of the total cost of resources used in electricity generation.

Table C-1: Retail price increases by customer class, increase on business-as-usual levels, no carbon price

	2009- 2020, % increase	2021-2035, % increase	2009- 2035, % increase	Average, $/MWh	Average, %
Energy Intensive Trade Exposed					
RET 10%	0.52%	-2.08%	-0.92%	-0.48	-0.54%
RET 15%	-1.76%	0.74%	-0.37%	-0.40	-0.46%
RET 20%	-0.50%	-2.94%	-1.86%	-1.04	-1.18%
Industrial					
RET 10%	2.08%	0.13%	1.00%	0.78	0.88%
RET 15%	2.24%	4.71%	3.61%	2.38	2.68%
RET 20%	5.12%	4.18%	4.60%	3.30	3.71%
Commercial					
RET 10%	1.43%	0.09%	0.69%	0.81	0.91%
RET 15%	1.55%	3.39%	2.57%	2.45	2.76%
RET 20%	3.53%	3.00%	3.24%	3.39	3.82%
Residential					
RET 10%	1.25%	0.08%	0.60%	0.83	0.93%
RET 15%	1.35%	2.98%	2.26%	2.53	2.84%
RET 20%	3.08%	2.64%	2.83%	3.49	3.93%

Refer to footnotes in Table 3-2 for details.

Table C-2: Additional expenditure on electricity purchases, no carbon price, $/year

	Household	Small business	Large business
RET 10%	6.8	37	27,323
RET 15%	15.1	82	60,218
RET 20%	23.6	129	94,403

Refer to footnotes in Table 3-3 for details.

Although resource costs of a renewable energy target are about the same in the absence of carbon pricing[25], greenhouse gas emissions reductions are projected to be about the same or greater (Table C-3). This is because generation displaced as a result of the targets is, on average, more emissions intensive in the absence of carbon pricing.

Table C-3: Reduction in greenhouse gas emissions in the SWIS, no carbon price, Mt per annum

Average abatement	2009-2020	2021-2035	2009-2035
RET 10%	0.5	0.8	0.7
RET 15%	0.8	1.9	1.4
RET 20%	1.3	2.6	2.0

Source: MMA analysis.

Analysis was undertaken on the impact of fifteen per cent target on the Western Australian economy, in the absence of carbon pricing. Economic activity is projected to be 0.09% lower by 2020. Business-as-usual levels of GSP in 2020 are reached just under two weeks later.

The employment impact peaks at 71 full time equivalents lower than business-as-usual scenarios in 2020. On average, the number of full time equivalent positions is lower by 25 positions over the study period.

[25] Resource costs of a renewable energy target will differ with a carbon price depending on two offsetting factors. First, renewable energy generation will tend to enter earlier the higher the carbon price, so that the present value of the additional renewable energy generation costs will be higher due to less discounting. Second, and offsetting the first factor, additional renewable energy generation will defer the need for other low emission options to enter the market. The present value of this saving tends to be higher the higher the carbon price.

Table C-4: Summary of impacts, no carbon price

	10%	15%	20%
Impacts			
Certificate price, $/certificate	39.3	44.8	44.8
Wholesale electricity price increase, %	1.4%	4.9%	6.3%
Retail price increase, %	0.6%	2.5%	3.0%
Resource costs, $M	164	399	612
GDP costs, $M	nc	-2,512	nc
Benefits			
Abatement of greenhouse gas in the SWIS, Mt CO_2e	14	29	41
Investment in renewable energy generation, $M	384	809	1,241

nc = not calculated. Source: MMA and CoPS analysis.