Report to

National Emissions Trading Taskforce

Impacts of a National Emissions Trading Scheme on Australia's Electricity Markets

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McLennan Magasanik Associates Pty Ltd
242 Ferrars Street
South Melbourne Vic 3205

Tel: (03) 9699 3977
Fax: (03) 9690 9881
Email: mma@mmassociates.com.au
Website: www.mmassociates.com.au

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1 INTRODUCTION

The National Emissions Trading Taskforce (the Taskforce) is exploring the potential impacts of a national greenhouse gas (GHG) emissions trading scheme (ETS) on:

- Costs of compliance.
- Growth trends for specific industries (e.g. energy intensive and trade exposed) and structural adjustment issues.
- Impacts on energy prices for customers, by region.
- Macroeconomic impacts such as economic growth, employment, investment and inflation.

The National Emissions Trading Taskforce engaged a consortium comprising the Allen Consulting Group (ACG), Insight Economics, McLennan Magasanik Associates (MMA) and Centre of Policy Studies (CoPS) to undertake an assessment of the cost and benefits of a national emissions trading scheme.

The Taskforce worked with the consortium to develop a range of ETS scenarios. These were based on earlier decisions by the States and Territories in relation to key design principles for an ETS, including the ten principles announced by States and Territories in 2005. These decisions were that:

- A cap and trade approach to be used as the basis for scheme design.
- The scheme be national and sector based.
- In setting the cap, consideration be given to the overall national emissions abatement target, and how the abatement responsibility is allocated between sectors covered by the scheme and those outside the scheme.
- The scheme initially covers the stationary energy sector (including electricity, gas and coal).
- The scheme cover all six greenhouse gases under the Kyoto Protocol.
- Permit allocation be made on the basis of a mix of administratively allocated and auctioned permits, with both long and short term (annual) permits.
- A penalty should be set to encourage compliance and to establish a price ceiling for the permit market.
- Offsets be allowed.
- Mechanisms be included to address any adverse effects and structural adjustments.
- Mechanisms be included to allow a transition for participants who have taken early abatement action and new entrants.

In this report we describe the impacts of the emissions trading scheme on the electricity market. Section 2 of the report describes the methodology and the assumptions used to estimate the impacts on the electricity market. The scenarios modelled – based around different structures and targets for the emissions trading scheme – are also described. Section 3 outlines and discusses the key results of the analysis for the scenarios where emissions trading is confined to Australia.

In total, the results of 3 scenarios are reported. The results discussed include:

- Permit prices.
- Level of emissions and abatement in the electricity generation sector.
- Impacts on wholesale electricity prices by region.
- Impacts on retail electricity prices by customer class by region.
- Impacts on investment in generation and generation levels by technology type.
- Impacts on resource costs in electricity generation.

Conclusions from the analysis are drawn in Section 4.

A separate report summarises the results of the modelling of macroeconomic impacts of emissions trading estimated using the MMRF-Green Computable General Equilibrium modelling by CoPS. The report provides the impacts on Gross Domestic Product, private consumption expenditure, employment, real wages and overall abatement of greenhouse gas emissions.

Please note monetary values are in mid 2005 dollar terms, unless otherwise stated.

2 METHOD AND ASSUMPTIONS

2.1 Overview

Examination of the abatement potential and cost of an emissions trading scheme 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 stationary energy sector. The output of the modelling included: the impacts on energy prices; impacts on the costs of different types of generation; and the interaction of scenarios and policy options with other greenhouse policies such as MRET. Timing and type of new investments in generation and energy efficiency for each region of the NEM was also an output of the modelling.
- The outputs of the MMA modelling were fed into CoPS' MMRF-GREEN model to determine the impact of different scenarios and policies on the broader Australian economy. MMRF-GREEN is the most comprehensive CGE model of the Australian economy with a major element relating to greenhouse gas emissions. The output of the MMRF–GREEN model included the impacts of scenarios and design options on greenhouse gas abatement, energy demand, employment levels, investment, GDP and inter–industry effects.

The first stage of the modelling was to develop input assumptions. MMA used an extensive database on supply costs for electricity generation and stationary energy activities and of future costs of new technologies for electricity generation and energy efficiency programs. The data base tracks projected changes in technology costs over time and the availability of the technologies. The database also contains the cost implications of fuel substitution to reduce emissions and hence allows for the modelling of conventional gas and coal fired options of varying capacities and capabilities, new generation technologies (clean coal, fuel cells, renewables) and modifications to existing generators (upgrades, re-powering, conversion options).

The second stage involved detailed modelling of the electricity markets over the timeframe of the study using MMA bottom up models of these markets. MMA's model of the National Electricity Market (NEM), South West Interconnected System (SWIS) and the Darwin Katherine Interconnected System (DKIS) simulates the market 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; and

- Impact of schemes such as Queensland's 13% gas-scheme and MRET on dispatch and electricity prices.[1]

Outputs from the bottom up models are then input into the MMRF model of the Australian economy, which is the third stage of the modelling process.

2.2 Modelling Impacts on the Electricity Market

Modelling the impact of the abatement policies on the electricity market is a complex process. It requires iteration between a number of models to determine both the direct impacts and interactions between the various schemes. For example, if emissions trading is introduced in the near future, this will directly impact on the type and cost of renewable generation facilitated under the MRET scheme.

Generally, an abatement policy will directly impact on the electricity market in one of two ways. An abatement policy will:

- Vary the energy demand volume and profile – typically through adoption of energy efficiency programs; or
- Vary the net marginal cost of generation and hence the merit order of dispatch, through a price impost engendered through emissions targets. Emissions trading schemes impact on the marginal cost of generation and hence the merit order of power plants. To the extent that these policies impact on electricity prices these policies could also impact on demand.

Figure 2-1 shows the interactions between the MMA models used, and how the abatement policies were incorporated into the analysis. The key models are discussed in more detail below.

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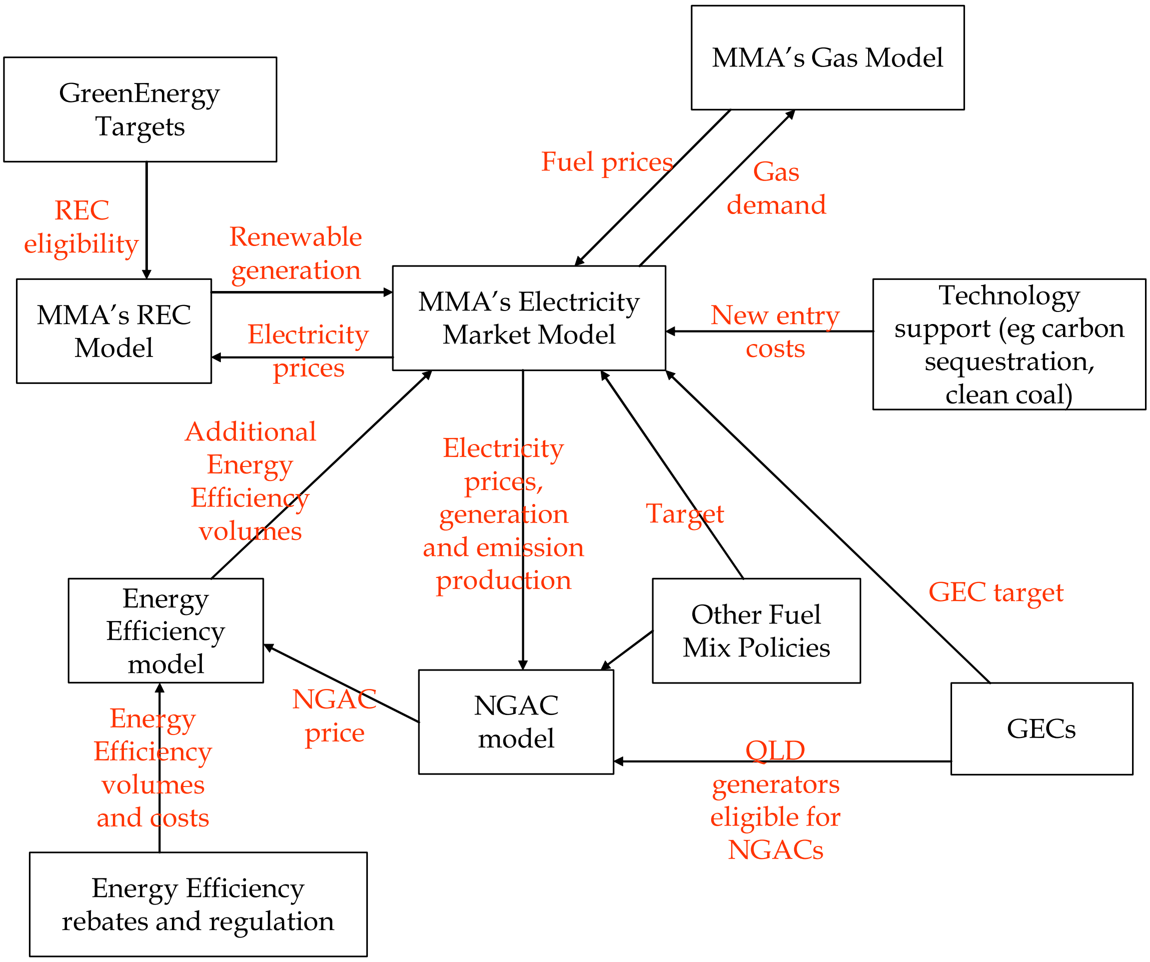
[1] Note the Victorian Renewable Energy Target scheme has not been inlcuded in the modelling.

Figure 2-1: Diagram of MMA's suite of models for assessing impact on energy sector



Our approach to modelling the electricity market, associated fuel combustion and emissions was to utilise electricity demand forecasts derived from the MMRF Model in our STRATEGIST models of the major electricity systems in Australia. The model accounts for the economic relationships between generating plant in the system. In particular, the model calculated production of each power station given the availability of the station, the availability of other power stations and the relative costs of each generating plant in the system.

Modelling of the electricity markets was conducted using a multi-area probabilistic dispatch algorithm. The 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 corresponding month.
- Chronological dispatches of hydro and pumped storage resources either within regions or across selected regions (hydro plant is assumed to shadow price to maximise revenue at times of peak demand).

- A range of bidding options for thermal plant to maximise profit from trading in the spot market is assumed up to the time new plant are needed. After new plant are needed, all plants bid at short run marginal cost in all regions
- Chronological dispatch of demand side programs, including interruptible loads and energy efficiency programs.
- Estimated inter-regional trading based on average hourly market prices derived from bids and the merit order and performance of thermal plant, and quadratic inter-regional loss functions.
- Scheduled and forced outage characteristics of thermal plant.

The model projected emissions by projecting expected levels of generation for each generating unit in the system. The level of utilisation depended on plant availability, their cost structure relative to other plant in the system and bidding strategies of the generators. Bids are mostly formulated as multiples of marginal cost and were varied above unity to represent the impact of contract positions and price support provided by dominant market participants.

New plant or energy efficiency programs, whether to meet load growth or to replace uneconomic plant, were chosen by the algorithm on two criteria:

- To ensure electricity supply requirements are met under most contingencies. We used a maximum energy not served of 0.002%, which is in line with the planning criteria used by NEMMCO. Plant will always be installed in the model to meet this criterion.
- Revenues earned by the new plant/energy efficiency program equal or exceed the long run average cost of the new generator/energy efficiency program. Additional plant could be installed according to this criterion above that required to meet the first criterion.

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.

Energy efficiency programs are also modelled by type of program and are incorporated as a negative load. Each program can be defined by costs of program (variable and fixed), payback periods, minimum savings required, minimum and maximum actions per day or per year (in the case of interruptible loads), hourly demand foregone profiles by season and year, and constraints on the rate of adoption.

Information required to project generation, emissions and system costs, include:

- Forecasts of load growth (peak demand, electricity consumption and the load profile throughout the year).

- Operating parameters and costs for energy efficiency programs. MMA currently splits energy efficiency programs into commercial, residential and industrial programs.
- Operating parameters for each plant including heat rate as a function of capacity utilisation, rated capacity, internal energy requirements, planned and unforeseen outage time.
- Data on fuel costs for each plant including mine mouth prices (or well head prices in the case of gas), rail freights (or transmission costs in the case of gas), royalty arrangements, take-or-pay components, escalation rates, quantity limits and energy content of the fuel.
- Variable unit operating and maintenance costs for each plant (which may also vary according to plant utilisation).
- Fixed operating and maintenance costs.
- Emissions production rates by fuel type.
- Annual hydro energy and allocation of generation on monthly basis.
- Capital costs for new generating plant.

2.3 Modelling of emissions trading

Details of the approaches used to model the different design options follows. As the policy options largely affected the electricity generation sector, the modelling of policies was undertaken by MMA using the simulation model of the electricity market. The impacts on electricity supply costs, electricity prices and generation by technology type was provided to CoPS to be input into the MMRF model to determine wider economic impacts.

Emissions trading involves setting a maximum level of emissions from electricity generation in each year. For this study, the following key assumptions were made by the National Emissions Trading Taskforce:

- Time line of emissions caps was assumed to be 2010 to 2030.
- Banking, but not borrowing is allowed, so that excess abatement can occur in earlier years, which can then be used redeem future abatement liabilities.
- No grandfathering was assumed.

Emissions trading was simulated in the electricity market models by setting a target of cumulative total carbon emissions for the study period. The cumulative target was set at the sum of the annual targets from 2010 to 2030. The model estimates the clearing price required to reach the target, where the clearing price (or permit price in each year) is equal to the marginal cost of the last abatement option required to be adopted to achieve the target.

As banking was allowed, the level of abatement in each year was optimised over the study period to achieve the cumulative level of emissions over the study period. The simulation model determines selection of new plant and dispatch of existing and new plant, taking into account different levels of the permit price. The model selects the optimal level of banking by effectively selecting the level of emissions in each year that minimises the cost of meeting the cumulative target over the study period.

The simulation model works as follows. In each year, a target level of emissions is set. The right to emit incurs an opportunity cost. The model increases the permit price per unit of emissions and adjusts this price incrementally until the target is reached. The permit price is another variable cost. As the permit price increases, the variable cost of each emitting generator also increases, with the level of increase in the variable cost of each generator dependent on its emissions intensity. For each generator, the variable cost increases according to the following formula:

Variable cost increase ($/MWh) = Thermal efficiency[2] *(GJ/MWh) * Emissions intensity of the fuel (t* CO_2e*/GJ) * Permit price ($/t* CO_2e*).*

As the variable cost varies, abatement occurs in three ways. First, the merit order of dispatch of generating plant will change so that more generation from low emitting generators occurs. The short run marginal cost of high emissions units will increase relatively more than the short run marginal cost of low emitting plants. At some permit price level, the low emitting plant will have a lower short run marginal cost than high emitting plant, causing these plants to be displaced ahead of high emitting plant.

The fuel emissions intensities and thermal efficiencies input into the model are shown in Appendix A.

Second, the higher price of electricity (when permit prices are included) induces a higher level of adoption of energy efficiency options. Energy efficiency options are modelled as negative loads (i.e. if chosen by the model they reduce demand).

Third, as permit prices increase, the selection and timing of entry of new plant can change. The model selects new plant based on a hierarchy of long run costs. Of the options available, the generation option which minimises long run costs of generation is chosen when a new plant is required.

The price at which the annual emissions target is met is effectively the permit price in that year. The permit price in each year is then the price at which the optimal annual levels of emissions are achieved.

We have also been asked to model an emissions trading scheme with biosequestration offsets. A model of forest sequestration was developed to estimate the amount of carbon sequestration as a function of carbon price.

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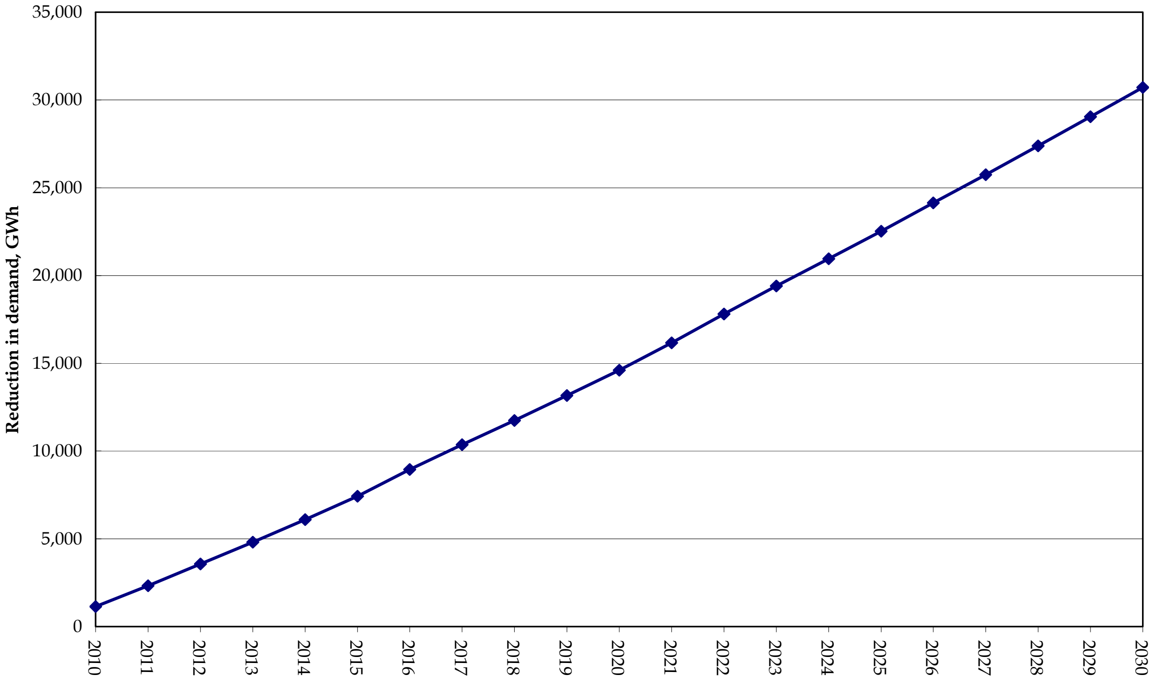
[2] Thermal efficiency is the efficiency with which the energy in the fuel is converted into electricity. Thus it is equal to the ratio of the energy content of the fuel used for generation (GJ) and the amount of electricity generated (MWh).

MMA also modelled the uptake of energy efficiency as part of the modelling process. In our energy efficiency model, end users adopt additional energy efficiency on the basis of the savings made in electricity purchases. That is, if the long term electricity price exceeds the long run marginal cost of an energy efficient option, then that option is assumed to be adopted. As emissions trading will increase the electricity price, so then it will also increase the adoption of energy efficiency. The data on the cost of energy efficiency options is contained in Appendix B.

A sensitivity was also conducted on a higher level of energy efficiency than encouraged under business as usual by our model. This higher level of energy efficiency was assumed to occur through other government programs designed to overcome key market barriers to the uptake of energy efficiency. The assumptions used were as developed by Insight Economics[3], and the impact on electricity demand is shown in the following chart.

Figure 2-2: Assumptions on the reduction in electricity demand with higher level of energy efficiency



2.4 Assumptions

2.4.1 General

A number of high level assumptions are employed in the modelling of all indicative policy scenarios. The following list summarises the high level assumptions:

- The market operates to maximise efficiency and is made up of informed, rational participants.

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[3] See Insight Economics (2006), The Economic Impacts of a National Emission Trading Scheme, report to the National Emission Trading Taskforce, June

- As a general principle in the scenario modelling, existing policy measures were retained. In the electricity sector, these included the Queensland Cleaner Energy Strategy and the MRET. However, in the modelling of emissions trading scenarios, the NSW and ACT Greenhouse Gas Abatement Scheme was assumed to cease in 2009 and be replaced by the ETS.

- MMRF's energy demand forecasts for the business as usual world are used in all scenarios. Annual demand shapes are then derived to be consistent with the relative growth in summer and winter peak demand implied in the NEMMCO, Western Australian Independent Market Operator and NT Utilities Commission's forecasts of electricity demand.

- Capacity is installed to meet the target reserve margin for the NEM, SWIS and the DKIS.

- The study period is 2010 to 2030, with policies assumed to commence in 2010.

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

- The capacity factor for hydro generators is assumed to be based on normal inflow conditions.

- Fuel prices for gas generators are estimated using MMA's gas market model.

- Assumed fuel prices for coal generators are based on published data on prices (such as ABARE's export coal price projections) and published data on contract quantities.

- 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. Existing clean coal technology such as Integrated Gasification Combined Cycle Plants (IGCC) and Ultra Clean Coal (UCC) are included as options in cost estimates. IGCC plant fitted with pre-combustion carbon capture and storage is also considered.

- Costs for renewable generation projects are derived from published sources of information. MMA maintains a database of renewable energy projects, which contains information on capacity, generation levels, operating costs, capital costs and other costs for each renewable generation project - operating, committed or planned.

- Real capital costs for all technologies are assumed to fall over time. A "capital cost reduction factor" is included for each technology in the analysis to model this effect.

- 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).

- Network upgrade costs are based on the Annual Planning Statements published by the State Jurisdictions and planning bodies. The data was used to make assumptions on the costs of both committed and planned interregional network upgrades.
- 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 prices will flow through to retail prices. Price increases are therefore borne by the broad customer base.

2.4.2 Cost of abatement technologies

A key component of the analysis of the impact of abatement costs is the cost of abatement technologies.

MMA holds a range of data on the demand and supply-side abatement opportunities currently available in Australia, in particular in terms of the cost implications of fuel substitution to reduce emissions. The model allows for the modelling of:

- Conventional gas and coal fired options of varying capacities and capabilities.
- New generation technologies (clean coal, fuel cells, renewables) including carbon storage and geosequestration technologies.
- Modifications to existing generators (upgrades, re-powering, conversion options).
- Renewable energy options.
- Energy efficiency options.

MMA has developed a full financial model to derive the relationship between capital expenditure, fuel price and electricity price to achieve a required rate of return for the new generating plant. Financial costs are developed for each generating technology type, fuel source and region in the NEM. Costs are varied over time using either historical trends or projections of decline of capital costs for new technologies. Some of the key inputs into the analysis of the financial costs include:

- Period of operation.
- Debt/equity ratios.
- Loan period.
- Interest rate on loans.
- Construction period.
- Physical characteristics such as maintenance requirements, forced and partial outage rates, and segmented heat rates, and capacities.
- Fuel Prices.

- Seasonal Variable Cost Profile.
- Fixed and Capital Costs.

For each technology option, the long run marginal cost of generation was derived by assuming a standard weighted average cost of capital (WACC) for the nominated coal or gas price range and capital cost estimates for each project (See Appendix B). The assumptions were input for each technology option into the electricity market model. The electricity market model then used an iterative programming algorithm, which selects the timing of entry and combination of new technologies and conventional technologies that minimises total electricity system costs and meets the NEMMCO supply reliability criteria over the study period. This choice was influenced by the abatement policies.

The gas prices for the cost curves for new gas fired options were obtained from MMA-Gas. MMA-Gas, Market Model Australia–Gas, replicates the essential features of the Australian wholesale gas market:

- A limited number of gas producers, with opportunities to exercise market power.
- Reliance upon new entrants to provide additional competition.
- Dominance of long-term contracting and very limited short-term trading.
- A developing network of regulated and competitive transmission pipelines.
- Market growth driven by gas-fired generation and large industrial projects.

MMA-Gas has been developed to provide the most realistic assessments of long-term outcomes in the Australian gas market, including gas pricing and quantities produced and transported to each regional market.

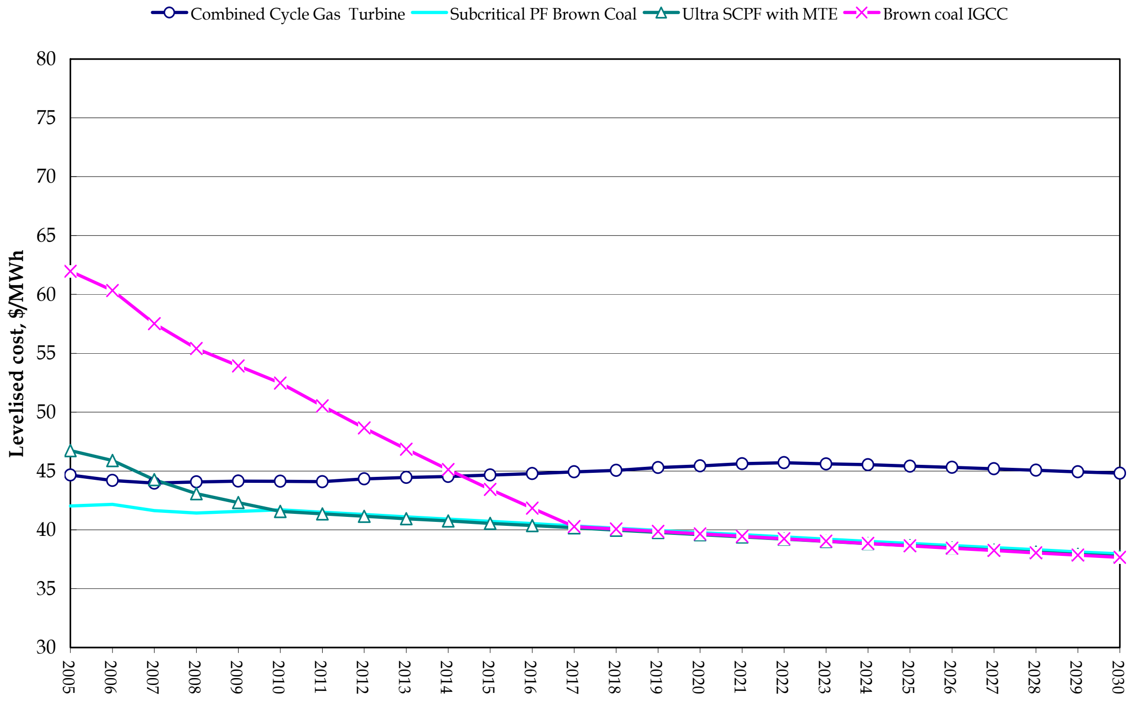
The “gas market” in MMA-Gas is the market for medium to long-term gas contracts between producers and buyers such as retailers or generators. Competition between producers is represented as a Nash-Cournot game, in which each producer seeks to maximise its profit subject to constraints imposed by its competitors. The role of buyers is replicated by modelling the activities of an arbitrage agent. Transmission costs are treated as cost inputs.

MMA-Gas represents the eastern states market as twenty separate producers competing in eight separate market zones: New South Wales, Victoria, South Australia, Tasmania, south east Queensland, central Queensland, north east Queensland and north west Queensland. Model parameters for this implementation have been estimated so that its outputs replicate published data on recent negotiated contract price and volume outcomes.

The assumed long run marginal costs of generation (without carbon impost) for new base load options in Victoria used in the modelling are shown in the following chart. The cost curves are illustrative of the average costs of each technology. Some new plant options will have lower costs than shown in the chart and some will have higher. For example, costs of CCGTs are assumed to be lower for options located close to gas fields or for which there is no alternative market for the gas. Brownfield expansions of plants are also assumed to have lower long run marginal costs

The trends for Victoria are illustrative of the trends in costs by technology type in other states.

Figure 2-3: Long run marginal cost of new generation options in Victoria, $/MWh, base load (90% capacity factor) options



Source: MMA analysis. Note the costs in this diagram are representative of the average estimates for each technology type. Costs for individual projects may vary as a result of locational factors. For example, gas costs may vary by location.

2.5 Emissions caps

The modelling was conducted using three sets of indicative emissions caps:

- Scenario 1: 'Moderating Stationary Energy Emissions' — cap electricity generation emissions at 176 Mt of CO_2e by 2030. The 176 Mt of CO_2e cap is equivalent to returning electricity generation sector emissions at 2000 levels.

- Scenario 1a: 'Complementary Policies Sensitivity' — as per Scenario 1, but with sensitivity for enhanced energy efficiency uptake induced demand side technical change and enhanced forestry biosequestration. In this sensitivity scenario the emissions quantity trajectory generally followed Scenario 1, but the emissions permit price was reduced due to the enhanced energy efficiency and forestry biosequestration offsets reducing the abatement required from the electricity generation sector.

- Scenario 2: 'Accelerated Stationary Energy Emissions Reductions' — cap electricity generation emissions at 150 Mt of CO_2e by 2030.

Based on modelling of emissions under business as usual conditions, the emissions trajectories for each of the emissions targets are shown in Figure 2-4. Under business as usual conditions, emissions are projected to grow by around 1.7% per annum from electricity generation in the NEM, SWIS and DKIS, from around 193 Mt CO_2e in 2010 to around 265 Mt CO_2e in 2030.

Figure 2-4: Emissions caps, electricity generation (combustion) emissions

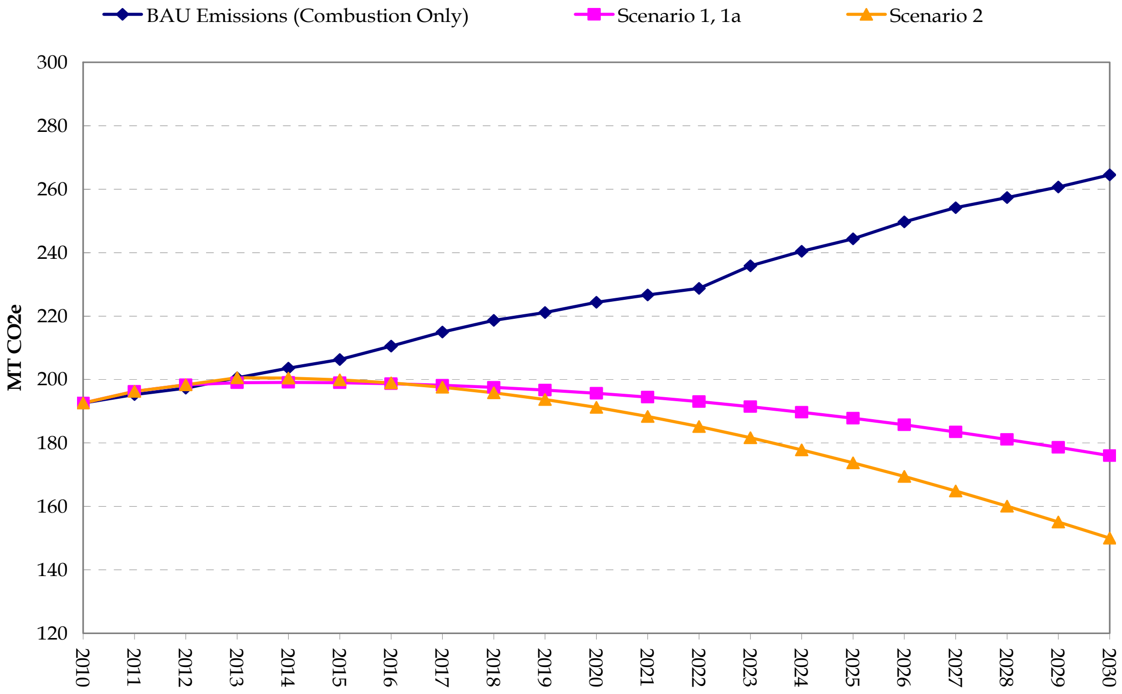


Table 2-1: Abatement caps relative to business as usual (combustion) emissions from electricity generation, Mt CO_2e

Year	Scenario 1, 1a	Scenario 2
2010	0	0
2011	0	0
2012	0	0
2013	0	0
2014	4	3
2015	7	6
2016	12	12
2017	17	17
2018	21	23
2019	24	27
2020	29	33
2021	32	38
2022	36	44
2023	44	54
2024	51	63
2025	57	71
2026	64	80
2027	71	89
2028	76	97
2029	82	106
2030	88	114

Source: MMA analysis

3 RESULTS – DOMESTIC ACTION SCENARIOS

3.1 Overview

Implementing any abatement measures for the specified caps will likely increase energy costs and hence impact on the energy industry and the wider economy. These impacts are set out below.

In the case of emissions trading, energy costs will be impacted both directly and indirectly. Fossil fuel generators will need to purchase a permit in order to generate a unit of electricity. For generators who are not allocated permits, the purchase price of the permit adds to their short run marginal cost because they are required to purchase another input (i.e. the permit) in order to generate. It will be assumed in this analysis that generators who were allocated free permits are also likely to add the permit price to the short run marginal as the permit represents an opportunity cost (i.e. the generators can elect to sell the permit to another generator so the permit has a market value). Energy costs are increased indirectly because there is a switch to more expensive low emissions technologies.

To put the analysis of impacts into perspective, the contribution to emissions under the business as usual case is shown in the following chart. The chart shows the predicted rise in emissions from electricity generation for the business as usual case derived from the simulation models of the electricity grids. Emissions are predicted to grow by around 1.7% per annum over the period to 2030. Emissions grow faster in some regions such as Queensland and NSW reflecting either a high growth rate in electricity demand (as in Queensland) and/or a dependence of coal fired generation to meet new growth (as in both Queensland and NSW). Western Australia, which is also predicted to have a high growth rates in energy demand, has a relatively low growth rate in emissions due to the prediction that the bulk of new generation will be gas-fired. This latter result depends on trends in gas prices in Western Australia, which are unclear at the moment.

As a result of the relatively higher growth rate in emissions, the share of total emissions from NSW and Queensland are predicted to grow slightly, whilst the shares in other States are expected to remain stable or fall slightly over the period to 2030.

Figure 3-1: Emissions under business as usual assumptions by State

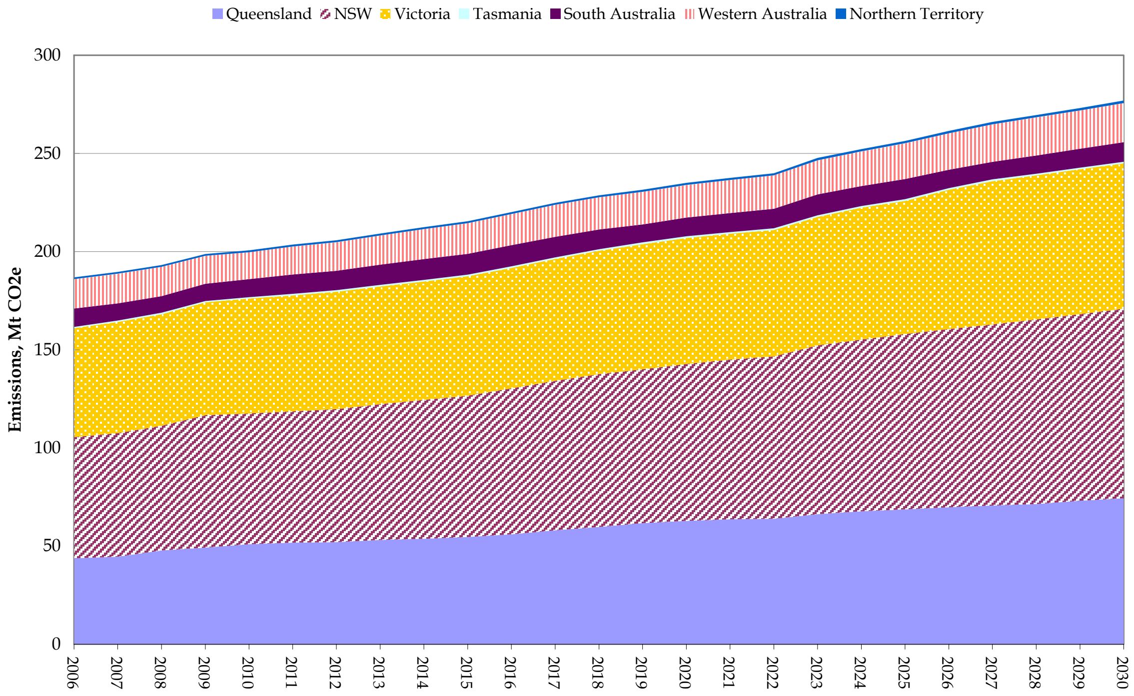


Table 3-1: Growth rate in emissions and share of emissions by State

	2007 - 2020	2021 - 2030	2010 to 2030
Growth rates, % per annum			
Total	1.7%	1.7%	1.7%
Queensland	2.6%	1.7%	2.2%
NSW	1.9%	1.9%	1.9%
Victoria	1.1%	1.4%	1.2%
Tasmania	1.9%	0.5%	1.3%
South Australia	0.3%	0.5%	0.4%
Western Australia	0.8%	1.8%	1.2%
Northern Territory	1.1%	1.7%	1.3%
Share of total emissions, % of total			
Queensland	25%	27%	26%
NSW	33%	35%	34%
Victoria	28%	27%	28%
Tasmania	0%	0%	0%
South Australia	5%	4%	4%
Western Australia	7%	7%	7%
Northern Territory	0%	0%	0%

Source: MMA analysis. Note: the zero values in the share of total emissions data represent values that are less than 1 per cent

3.2 Abatement

The level of abatement as modelled for each domestic action scenario is shown in the following chart. Abatement is slow in the early years due to the limited scope for introducing new low emissions plant into the mix and the limited opportunities for energy efficiency assumed in domestic scenarios 1 and 2. The model predicts that most of the abatement in this period comes from change in the dispatch order favouring low emissions intensity plant such as gas plant.

Abatement in the later years picks up, reaching around 55 Mtpa by 2030 for Scenario 1 and 75 Mt for Scenario 1a. From 2020, abatement occurs by:

- Marked increase in the level of renewable generation.
- Conversion of IGGC coal plant to include pre combustion carbon capture and storage.
- Change in the dispatch of existing plant.
- Retirement of some old coal fired plant (in the NEM).

Total levels of abatement (including offsets) over the period from 2010 to 2020 are shown in Table 3-2. Scenarios 1 and 1a achieve the same emissions cap and level of abatement over the study period. However, more abatement occurs through offsets under Scenario 1a, so the level of emissions from electricity generation is slightly higher in this scenario than for Scenario 1 (see Figure 3-3).

Figure 3-2: Abatement pathway

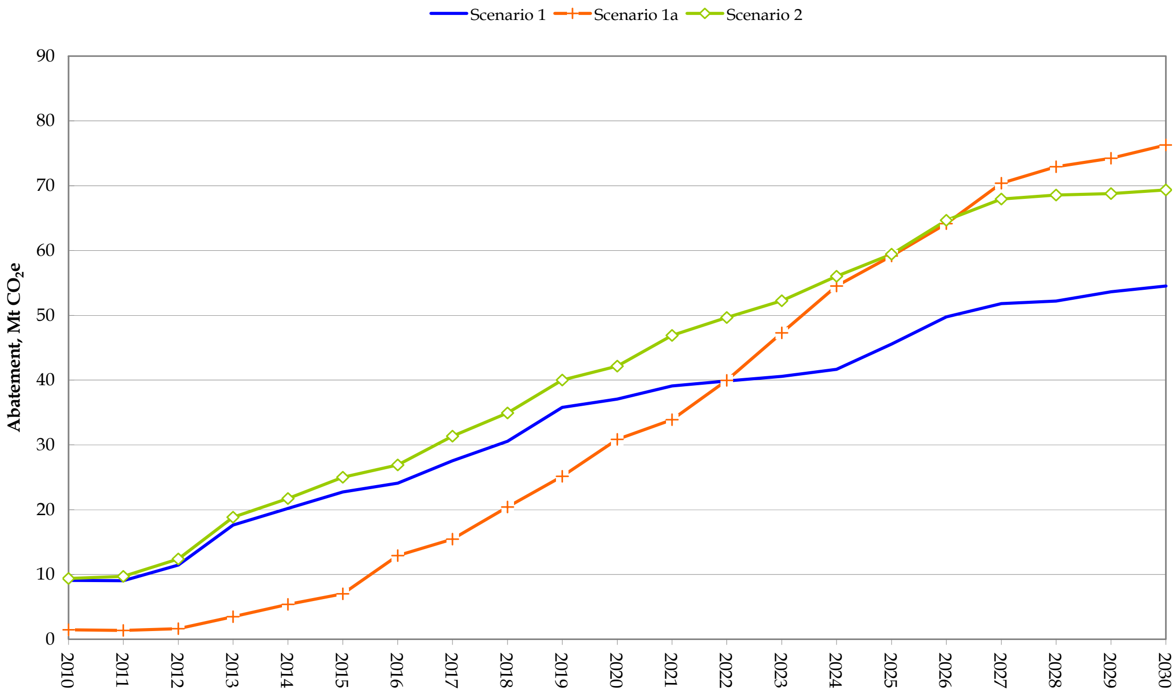


Figure 3-3: Emissions from electricity generation (combustion only)

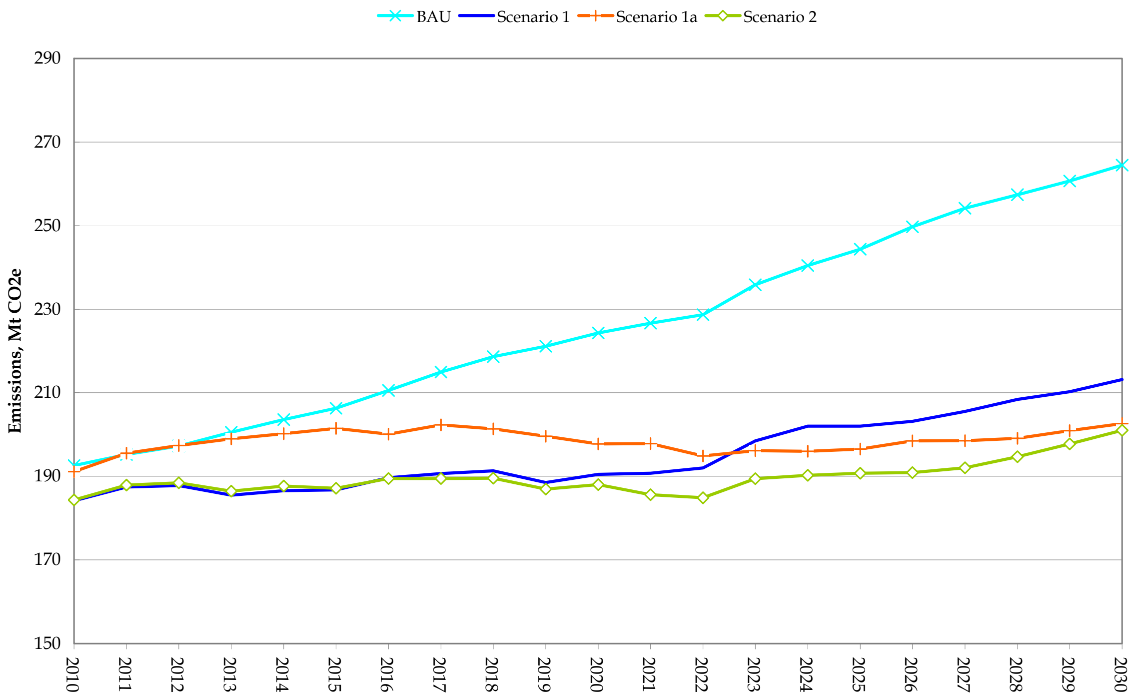


Table 3-2: Cumulative abatement, Mt CO_2e

	2010 - 2020	2021 - 2030	Total
Scenario 1 - Total	245	469	714
Electricity sector	216	437	653
Biosequestration	29	32	61
Scenario 1a - Total	125	593	718
Electricity sector	99	482	581
Biosequestration	26	111	137
Scenario 2 - Total	272	604	876
Electricity sector	219	545	764
Biosequestration	53	59	112

Source: MMA analysis

In scenario 1a, the level of sequestration offsets is more sensitive to the permit price than to other scenarios[4]. The level of biosequestration offsets is lower in the period to 2020 in this scenario due to the lower permit price that occurs during this period. From 2020

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[4] The level of biosequestration in this scenario is based on information provided by the Victorian Department of Sustainability and Environment, which suggested a level of biosequestration about two to three times higher than that predicted by MMA's model. For scenario 1a, MMA used the data provided to derive a new relationhsip between the level of biosequestration and permit price which reflect this order of magnitude difference in the potential for biosequestration.

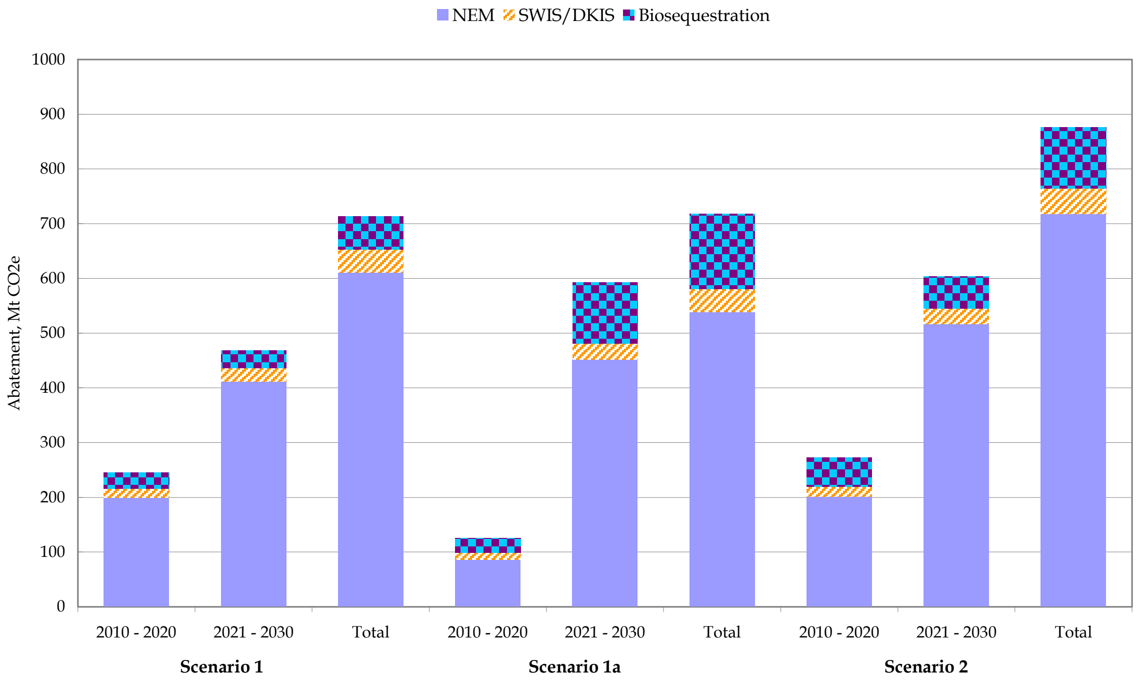
onwards, however, the high permit price encourages a level of biosequestration up to 2 to 3 times higher than in other scenarios.

In all scenarios, the level of abatement is higher in the period after 2020 than in the period from 2010 to 2020. This occurs for three reasons:

- Higher permit prices in the period from 2021 to 2030.
- The assumption that carbon capture and storage technologies become available at costs commensurate with the permit price in the period from 2021 to 2030, so that these technologies are adopted in this period.
- Greater adoption of renewable technologies in this period because of the assumed cost decline for these technologies.

The bulk of the abatement occurs in the NEM (see Figure 3-4). In the period to 2020, abatement in the NEM accounts for less than 80% of total abatement (and is as low as 54% in 2012). Abatement in the SWIS in the early period is important because of the relatively smaller difference in the short run marginal cost between coal and gas fired electricity in the SWIS. Thus, the SWIS is a major source of abatement from fuel switching, which accounts for up to 20% of the abatement in the period to 2018. Biosequestration is also a major source of early abatement although some caution should be taken in interpreting these results as the assumptions are indicative only.

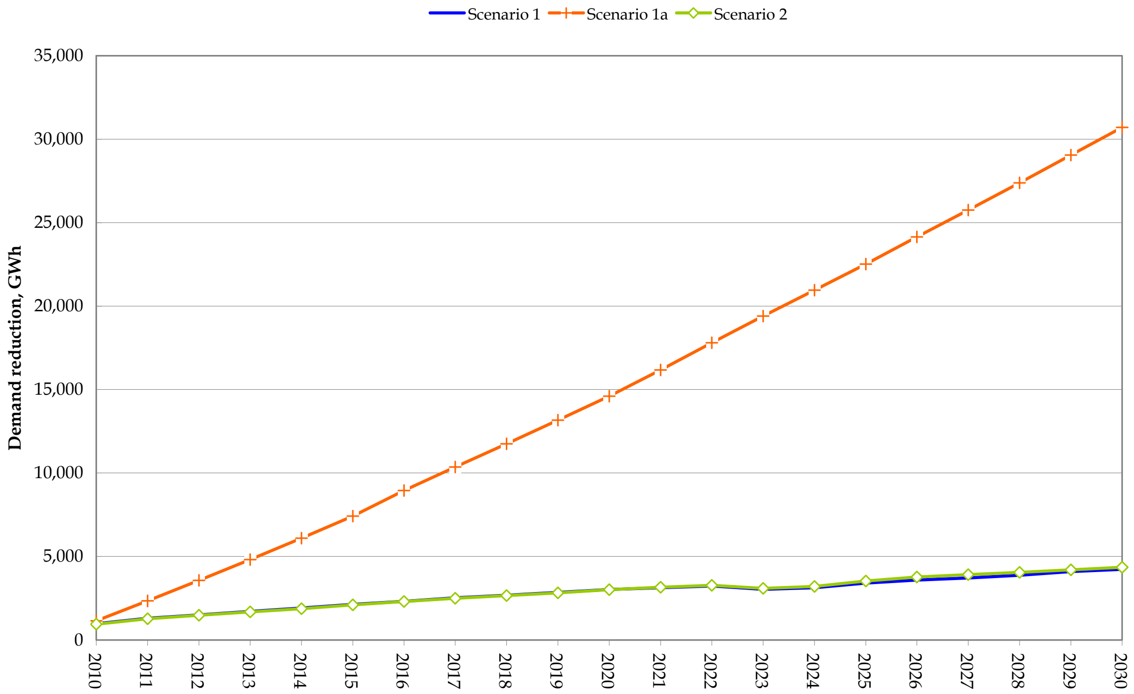
Figure 3-4: Abatement by source



In the period beyond 2020, emissions abatement from the SWIS and DKIS stabilise. Additional abatement in this period comes mainly from the introduction of new low emissions plant in the NEM. By 2030, the NEM accounts for around 86% of total abatement for Scenario 1 and 84% of total abatement for Scenario 2. The contribution from the SWIS falls to around 3%.

Part of the abatement in emissions occurs through the uptake of energy efficiency to reduce the demand for electricity generation. The level of demand reduction through energy efficiency uptake in Scenarios 1 and 2 are similar, varying from 1.5% of total demand for Scenario 1 and 2% of total demand for Scenario 2. This reflects the low sensitivity of energy efficiency to electricity price increases assumed in the modelling. For Scenario 1a, the implementation of government programs to remove barriers results in a significantly higher uptake of energy efficiency. In this scenario, the level of demand on a sent out basis is reduced (compared to BAU demand) by just under 8% in 2020 and by just under 14% in 2030 as a result of the uptake of energy efficiency.

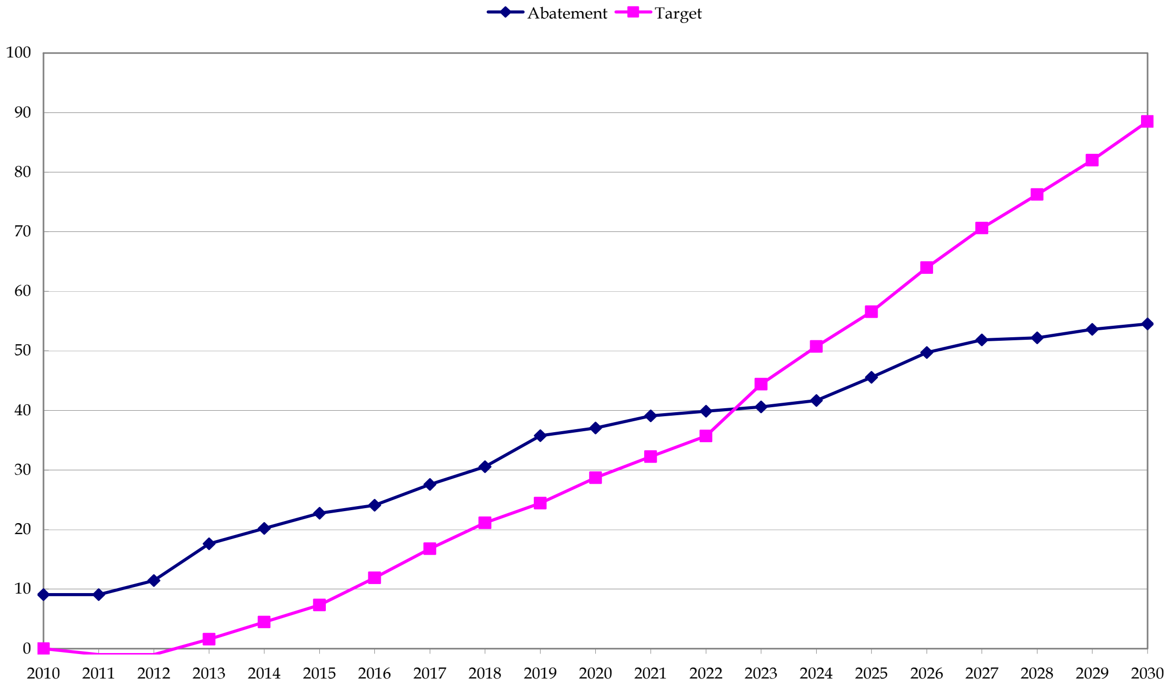
Figure 3-5: Load reduction through energy efficiency



The clear result that emerges is that even where a low level of abatement is required in the early years, the incentives provided by banking results in a high level of abatement in the early period. Abatement is lower than the target in the latter period, which helps to minimise the cost in that period. For example, Figure 3-6 shows that the level of abatement for Scenario 1 exceeds the target level of abatement in the period to 2022. By 2022, up to 133 million permits are estimated to be banked representing around two thirds of annual emissions. With such a high level of banking, the simulations show that the level of abatement in the period from 2022 is significantly below the target. Abatement hovers around 40 Mtpa to 55 Mtpa in this period, compared with a target level of abatement under the cap (relative to business as usual) increasing to about 90 Mtpa.

Placing restrictions on banking are likely to lower permit prices in early years, but increase them in later years. This will lead to significantly higher long term costs to liable parties and customers. It is also likely to call forth early retirement of more existing plant in order to achieve the cuts in emissions required.

Figure 3-6: Level of abatement versus target abatement, Scenario 1



3.3 Value of permits

The total value of permits comprises the value of permits traded in the market. Under an emissions trading scheme, it is equal to the number of permits required to be redeemed in each year multiplied by the permit price in each year.

Estimates of the value of the permits are shown in Table 3-3. The net present value of the permits in the study period (2010 to 2030) is around $41 billion for Scenario 1, $29 billion for Scenario 1a and $45 billion for Scenario 2, using a 6% discount rate. The value is lower under Scenario 1a compared to 1 because lower cost abatement is available to achieve the same cap.

Table 3-3: Value of permits

	Scenario 1			Scenario 1a			Scenario 2		
	Permit price, $/t	**Emissions, Mt**	**Value of permits, $M**	**Permit Price, $/t**	**Emissions, Mt**	**Value of permits, $M**	**Carbon price, $/t**	**Emissions, Mt**	**Value of permits, $M**
2010	12.0	184	2,210	6.0	191	1,147	12.0	184	2,213
2011	13.2	187	2,479	6.7	196	1,302	13.2	188	2,480
2012	14.5	188	2,728	7.4	197	1,459	14.5	188	2,736
2013	16.0	186	2,968	8.2	199	1,633	16.0	186	2,978
2014	17.6	187	3,275	9.1	200	1,824	17.6	188	3,298
2015	19.0	187	3,557	10.1	202	2,037	19.3	187	3,617
2016	20.5	190	3,891	11.2	200	2,246	21.3	190	4,029
2017	21.9	191	4,172	12.5	202	2,520	23.4	189	4,431
2018	23.2	191	4,447	13.8	201	2,785	25.7	190	4,876
2019	24.6	189	4,641	15.3	200	3,064	28.3	187	5,290
2020	26.0	190	4,949	17.0	198	3,369	31.1	188	5,852
2021	27.1	191	5,160	18.9	198	3,741	34.0	186	6,311
2022	28.0	192	5,380	21.0	195	4,091	33.9	185	6,261
2023	28.5	198	5,653	23.7	196	4,649	33.7	189	6,389
2024	28.8	202	5,808	24.9	196	4,877	33.6	190	6,391
2025	29.1	202	5,872	26.1	197	5,136	33.5	191	6,383
2026	29.1	203	5,920	27.4	198	5,445	33.3	191	6,362
2027	29.2	206	6,007	27.4	199	5,430	33.2	192	6,375
2028	29.2	208	6,092	27.3	199	5,430	33.1	195	6,436
2029	29.2	210	6,145	27.2	201	5,464	32.9	198	6,512
2030	29.2	213	6,230	28.4	203	5,761	32.8	201	6,592

Source: MMA analysis

3.4 Electricity prices

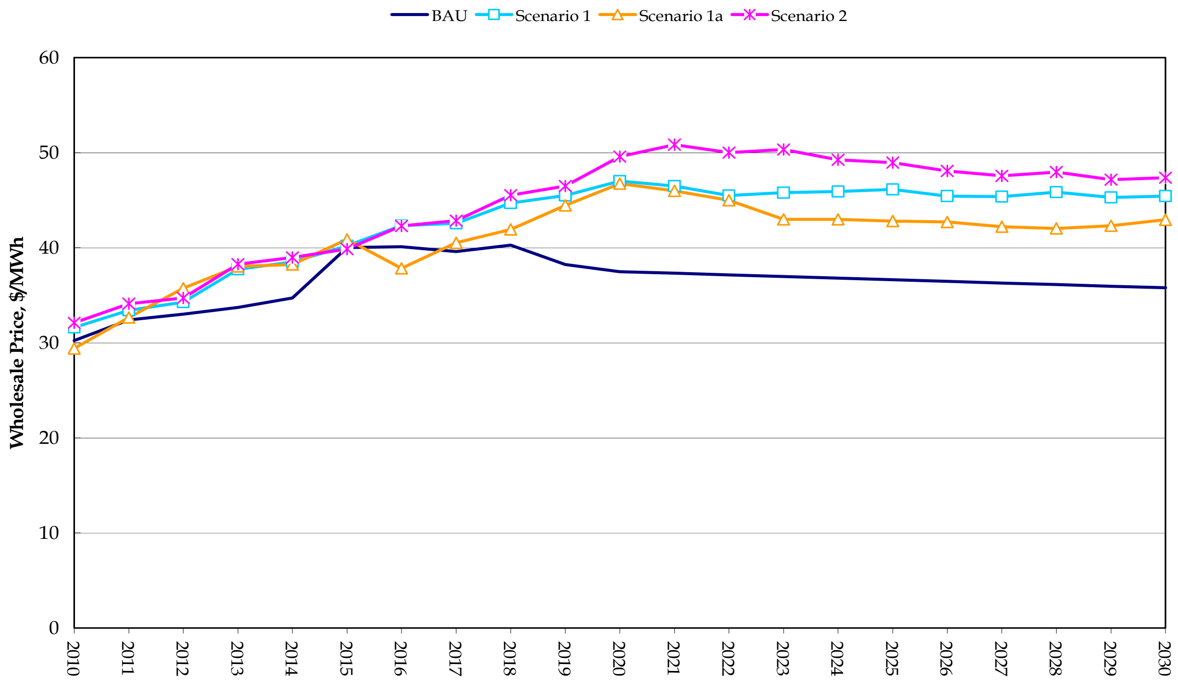
Wholesale and retail prices increase relative to business as usual (BAU) as a result of the impost of emissions as the permit price adds directly to the dispatch cost of generation.

In the NEM, wholesale electricity prices average around $36/MWh under BAU (see Figure 3-7). Under Scenario 1, wholesale prices increase to an annual average of $43/MWh. Under Scenario 2, wholesale prices increase to $44/MWh. Under Scenario 1a, a high level of energy efficiency depresses the impact on wholesale market prices from 2015 onwards as lower permit prices are required and the higher level of energy efficiency extends the period of capacity surplus in the market. Prices in this scenario increase towards the levels in Scenario 1 by 2020 (as prices need to increase to encourage entry of new plant), but then become lower again as lower permit prices are required.

There are variations between the States in the impacts on electricity prices across the scenarios. For example, although prices are lower overall across the NEM in Scenario 1a compared with Scenario 1, in some states the price increases. This is due to differences in the level of demand reduction due to energy efficiency across the States[5] and the differences in the level and timing for the need for new plant. Care should be taken in interpreting the variations across the states as these variations may reflect assumptions on the level of energy efficiency across the states as well as assumptions on the cost of new plants between the States.

Figure 3-7: Changes in wholesale electricity prices

(a) NEM



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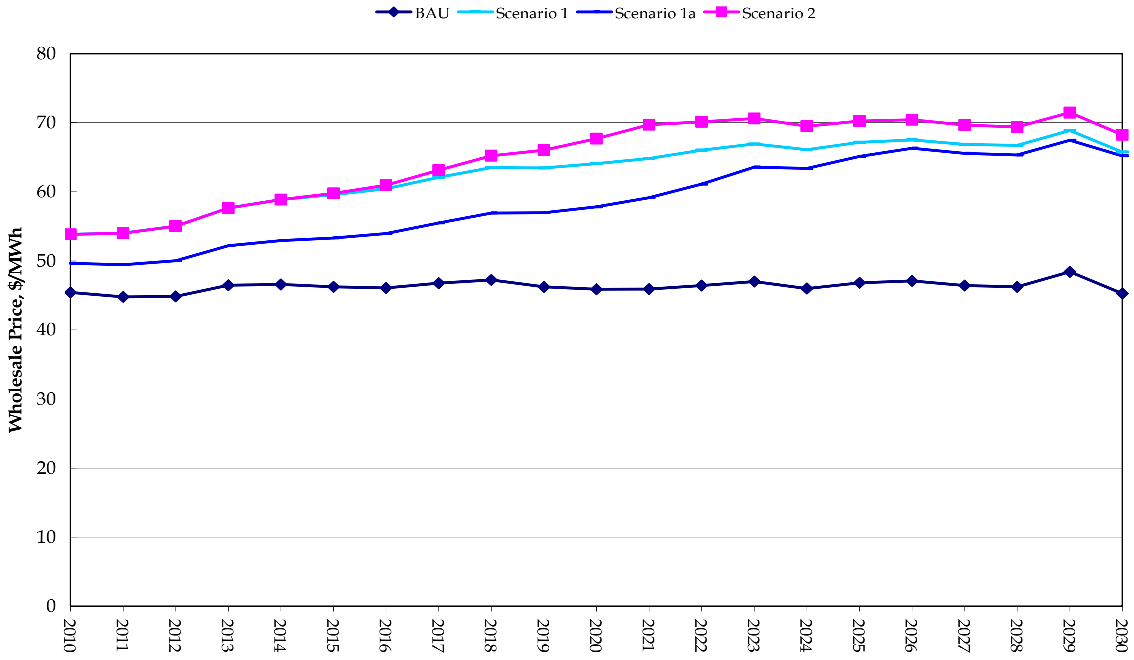
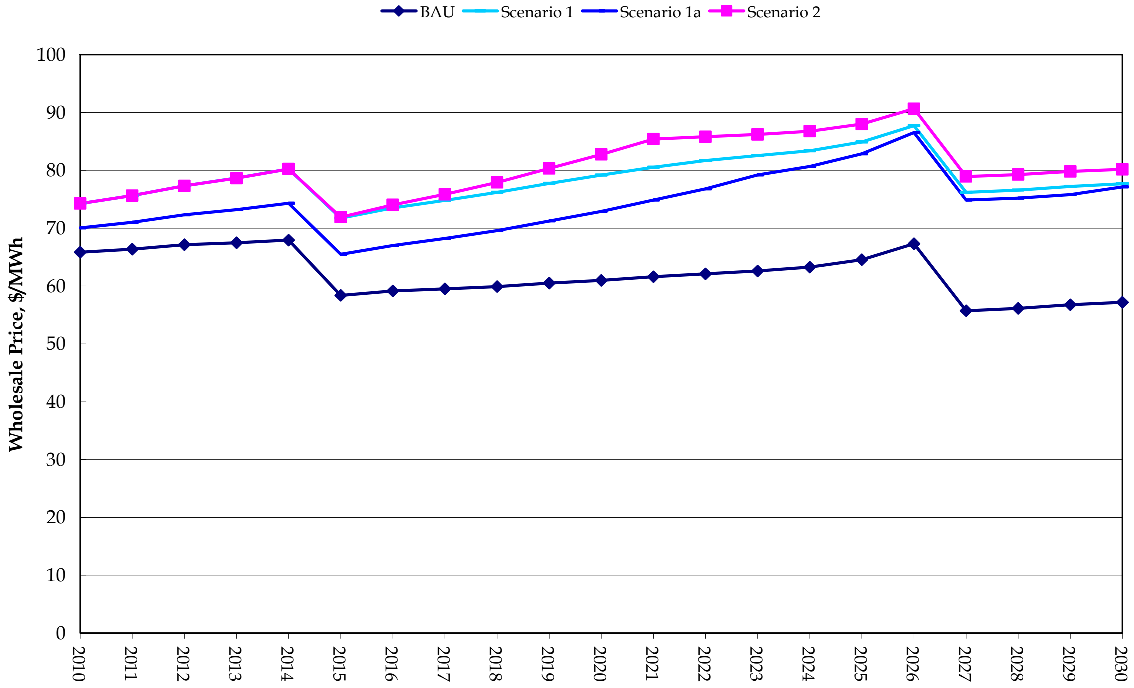
[5] An examinsation of the energy efficiency assumptions behind Scenario 1a reveals that a high proportion of energy efficiency occurred in NSW and low proportion in Queensland.

(b) SWIS



(c) DKIS



The percentage increase in the wholesale price of electricity is shown in Table 3-4. The price increase varies across the States and by scenario. Across the NEM, prices increase on average by 17% in Scenario 1 to 22% in Scenario 2. Price increases tend to be significantly lower in the first 10 years of the scheme, reflecting low caps and limited opportunities for wholesale abatement in the period up to 2020. The price increase after 2020 is determined by the marginal cost of low emissions plant, which includes clean coal plant with carbon capture and storage and renewable generation plant.

Table 3-4: Increase in wholesale electricity price

State	Unit	Scenario 1			Scenario 1a			Scenario 2		
		2010-2020	2021-30	2010 - 2030	2010-2020	2021-30	2010 - 2030	2010-2020	2021-30	2010 - 2030
NEM										
Price increase	$/MWh	3	9	6	2	7	4	4	12	8
Percentage increase	%	10	25	17	7	18	12	11	33	22
Western Australia										
Price increase	$/MWh	13	20	17	7	18	12	14	23	19
Percentage increase	%	29	43	36	16	38	27	31	50	40
Northern Territory										
Price increase	$/MWh	13	20	17	7	18	12	14	23	19
Percentage increase	%	21	33	27	12	29	20	23	39	30

The impact on wholesale prices differs amongst the regions. The percentage increase is greater in regions that have low wholesale prices in the business as usual scenario (e.g.: Queensland) than for regions with high prices under business as usual conditions and with plentiful abatement opportunities at low cost. Prices in the SWIS and DKIS also increase markedly because of limited abatement opportunities, less variability in the type of plant available to set price, no CCS plant entering these markets so they always have a fossil fuel plant with emissions setting the price, and in the case of the SWIS a switch to coal fired plant setting the price in the wholesale market. Although prices for Queensland increase more than for other NEM states, its increase is relatively less than for Western Australia, the major competing state to Queensland for energy intensive mineral and mineral processing based projects.

The average price increase in the NEM relative to BAU is relatively low. The modest increase in prices from BAU levels in the NEM is due to:

- In the emission trading scenarios, there is a level of energy efficiency brought on by the higher prices, which reduces electricity demand and delays the time when new entry is required. This is particularly the case in Scenario 1a, where there is a high level of energy efficiency. This tends to dampen electricity prices, particularly in the period prior to 2020. This is because we get longer gaps where there is overcapacity, because increments in supply are lumpy, and with lower demand it takes longer to absorb any new plant that is added.

- Increased uptake of renewable energy. As a high proportion of this is wind, there is also a need for some more peaking plant to ensure reliability of supply when the wind is not available during the peak period. This leads to slightly more capacity in the system than would be required otherwise. Further, this plant is bid into the model at short run marginal cost, whereas in reality it might be bid in at much higher levels in its backup role. The high uptake of renewable energy in states such as South Australia causes prices to be dampened in that State.

- Because the cost of transport and storage of carbon dioxide is assumed to be a variable cost in the model, this adds to the dispatch cost of IGCC plant with CCS. In some periods, these plants set the price and as their carbon intensity is low the marginal increase is relatively lower.

- There is a substantial amount of embedded generation entering the NEM induced by high carbon prices[6], which again reduces the demand seen in the wholesale market in the emission trading scenarios.

- Assumed improvement of energy efficiency of new plant due to technical change over time. This applies to gas turbine technology as well as IGCC technology. This means that the assumed emissions intensity reduces over time, so the emissions-inclusive marginal costs are dampened over time.

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[6] Which explains part of the increase in gas capacity under the emission trading scenarios.

- Improvement in energy efficiency of some existing plant, induced by incentive of emission trading to reduce the carbon footprint of each plant.

Alternative assumptions may lead to higher electricity prices than recorded in this analysis.

The highest increase in price occurs in Western Australia. The estimated increase in price applies only to customers connected to the South West Interconnected System (SWIS), which covers customers located in the south west corner of Western Australia. The price increase would not necessarily be as high in other regions of Western Australia (if they were included in a national emission trading scheme) due to predominant use of gas and liquid fuels in those regions, which have a lower emission intensity from combustion than the coal fired plant that supply a large part of the load in the SWIS.

The high increase in the SWIS is due to the fact that there is a high level of fuel switching such that coal plant are setting the price at the margin for a higher proportion of dispatch intervals. However, there is a likelihood that the price increase in Western Australia relative to the price increase in other States may be significantly lower than estimated due to the following reasons:

- Conservative assumptions on the uptake of energy efficiency options in Western Australia. Most of the data available on energy efficiency applies to the eastern States. The analysis reflected a low level of energy efficiency potential for Western Australia due to the lack of data on this potential. A higher level of energy efficiency in Western Australia than assumed would have led to a lower wholesale price increase due to emission trading.
- Existing fuel contract commitments by Verve Energy and private energy generators were assumed to have some flexibility in the quantity taken to allow for fuel switching to occur. However, if the contract quantities have to be taken then the ability to switch fuels (away from coal) will be hampered leading to a lower proportion of time that coal plants set the price under an emission trading scheme[7].
- Coal prices and gas prices may differ from those assumed. A lower coal price or a higher gas price would make it more difficult to switch fuels for a given permit price and would again reduce the proportion of time that coal plant set the price in the wholesale market.
- Restrictions on the uptake of renewables. The analysis assumed there was a limit on the amount of wind that the SWIS could cope with. It was assumed that no more than 500 MW of wind could be installed in the SWIS in the period to 2020 in Scenarios 1 and 1a, which includes the around 200 MW of capacity which will be installed by the end of 2008. If the grid could cope, more wind generation is likely to enter the SWIS given the good wind resources in the region and the relatively higher fossil fuel generation cost.

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[7] Although this would also lead to a higher emission permit price applying to all generators in Australia.

- Conservative assumptions on the uptake of new low emission fossil fuel technologies. We assumed no new low emission technologies was adopted in the SWIS due to the small scale of the plant required in the SWIS and the low amounts of captured carbon that would mean that economies of scale in piping and storage may not be achieved.

Retail prices increases compared to BAU are less than wholesale price increases (see Table 3-5). For Scenario 1, the price increases at the retail level across all jurisdictions averages around 12% prior to 2020. Prices increase gradually to be about 25% higher from 2020 onwards, averaged across all jurisdictions. The price increase is less for Scenario 1a, at about 7% across all jurisdictions for the period to 2020 and 15% for the period from 2021 to 2030, reflecting the lower abatement task at hand and hence the lower compliance cost. Of course, the increase in this scenario does not take into any increase in retail price to pay for any energy efficiency program that may be implemented. For Scenario 2, retail prices increase on average by between 14% in the period to 2020 to around 30% in the period after 2020.

The retail price impact is greater for industrial customers, because the wholesale price is typically a high proportion of the total retail price for these customers. For energy intensive customers, the average prices increase over the period from 2010 to 2030 ranges from 2% (South Australia) to 27% (Western Australia and Queensland) for Scenario 1a, and from 6% (South Australia) to 37% (Western Australia) for Scenario 2.

For residential customers, the relative price increase is less. Table 3-6 shows that the additional average weekly expenditure on electricity[8] over the period from 2010 to 2030 as a result of emissions trading varies from:

- $1.00/week in Victoria to $3.20/week in the Northern Territory for Scenario 1.
- $0.70/week in South Australia and Victoria to $2.20/week in the Northern Territory for Scenario 1a.
- $1.20/week in Victoria to $3.60/week in the Northern Territory for Scenario 2.

The relative increase across the States reflects both the variation in the increase in electricity prices as a result of emissions trading and variations in the amount of electricity used by households across the States. States with relatively higher level of electricity consumption at the household level (e.g. Tasmania, Northern Territory, Queensland and New South Wales) have a higher relative increase in average weekly expenditure than states with relatively low levels of electricity consumption (usually States with households connected to gas networks such as Victoria and South Australia).

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[8] The additional average weekly expenditure on electricity was calculated by multiplying the weekly average consumption of electricity by States (as published by the ESAA) multiplied by the average increase in retail electricity prices in $/MWh. For the NEM, an average retail prices increase across all NEM States was used.

Table 3-5: Percentage increase in retail prices from BAU levels by customer class, %

	Scenario 1			Scenario 1a			Scenario 2		
	2010-2020	2021-30	2010 to 2030	2010-2020	2021-30	2010 to 2030	2010-2020	2021-30	2010 to 2030
NEM States									
Industrial	9	23	16	8	20	14	11	29	20
Commercial	6	15	10	5	13	9	7	19	13
Residential	5	13	9	4	11	8	6	16	11
Western Australia									
Industrial	25	36	30	15	32	23	26	42	34
Commercial	17	26	21	10	23	16	18	29	23
Residential	15	22	18	9	20	14	16	26	20
Northern Territory									
Industrial	20	29	24	12	26	19	21	34	27
Commercial	14	22	18	9	20	14	15	25	20
Residential	13	20	16	8	17	12	13	22	18

Source: MMA Analysis

Table 3-6: Additional expenditure by residential customers, $/week

	Scenario 1		Scenario 1a		Scenario 2	
	2010-2020	2021-2030	2010-2020	2021-2030	2010-2020	2021-2030
Queensland	0.78	1.80	0.61	1.38	0.91	2.29
NSW/ACT	0.80	1.84	0.62	1.42	0.94	2.34
Victoria	0.59	1.36	0.46	1.05	0.69	1.73
South Australia	0.65	1.50	0.51	1.15	0.76	1.90
Tasmania	1.05	2.42	0.82	1.86	1.23	3.07
WA	1.85	2.69	1.08	2.09	1.96	3.08
NT	2.65	3.84	1.54	2.99	2.80	4.41

Source: MMA analysis

As many of the energy intensive industrial customers are trade exposed, there is the prospect that they may not be able to pass on the increase in energy costs. One way of avoiding this is to use revenue from auctioning of permits to compensate these customers. Alternatively, they can be allocated free permits to the equivalent value of the higher electricity costs they pay.

The NETT asked MMA to estimate the increases in electricity costs to these customers, and calculate how many permits would be required to give an equivalent value to that cost increase. The estimate of the compensation in each year was calculated by multiplying the increase in time weighted average electricity prices to these customers by the demand for electricity (on a sent out basis) by these customers.

The energy intensive customers were defined as those industries who where trade exposed and who had a proportion of electricity costs greater than 3.5% of total operating costs.[9] The industries included:

- Aluminium and alumina.
- Iron and steel.
- Cement and cement products.
- Non metallic mineral products.
- Non ferrous mining

These customers comprise around 31% of the total electricity demand.

Figure 3-8 shows an estimate of the additional electricity costs for energy intensive industrial customers that could be compensated through a free allocation of permits to an equivalent value. These costs increase over time in line with the increase in the permit price. In the period to 2020, the additional cost ranges from $250 million per annum to $1,500 million per annum. In the period after 2020, the additional cost ranges from $1,500

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[9] It is noted that the NETT has not made a decision on which firms will compensated.

million per annum to $2,500 million per annum. Costs are highest for Scenario 2, reflecting the higher target level of abatement required. Costs are lowest for scenario 1a, reflecting the lower permit prices in this scenario.

Figure 3-8: Additional electricity costs for energy intensive customers (calculated for compensation purposes)

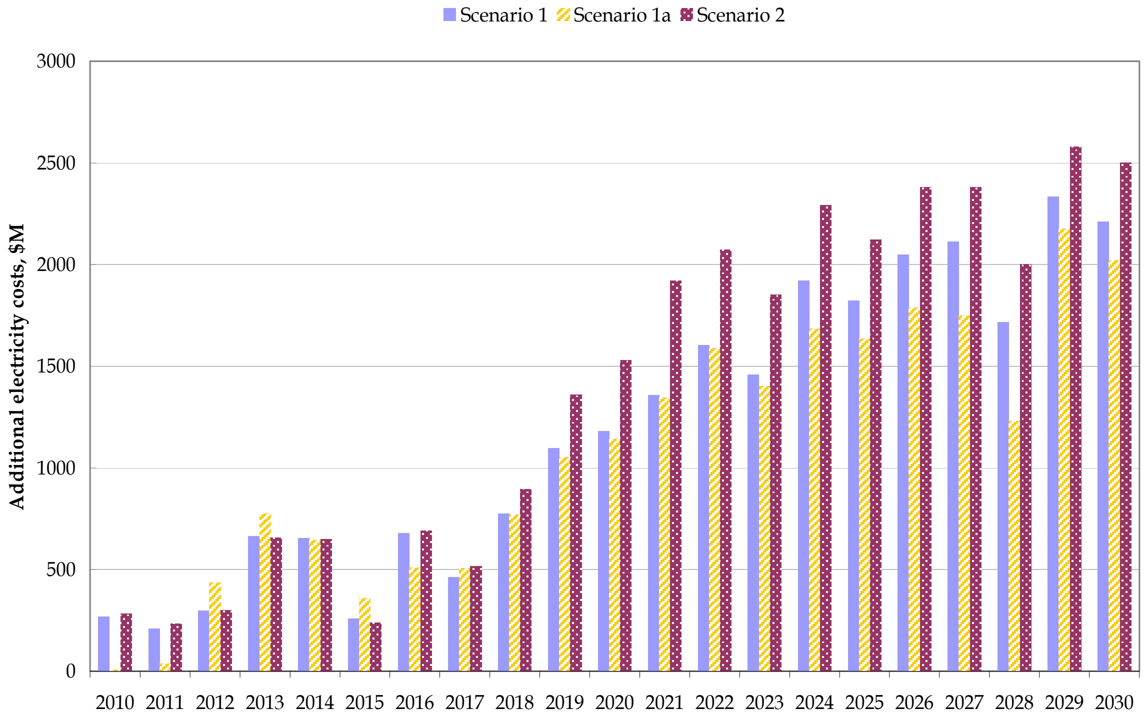

Table 3-7: Net present value of additional electricity costs incurred by energy intensive customers (calculated for compensation purposes)

	2010 to 2020	2021 to 2030	2010 to 2030
Scenario 1	3,634	5,910	9,545
Scenario 1a	3,404	5,320	8,724
Scenario 2	4,013	7,101	11,113

Note: Net present values calculated using a real pre-tax discount rate of 6%

Assuming the permit prices projected by the simulation model and a 6% real discount rate, the compensation for energy intensive customers over the period from 2010 to 2030 has been calculated to be:

- For Scenario 1, about $9.5 billion, or about 19% of the total value of permits.
- For Scenario 1a, about $8.7 billion, or about 25% of the total value of permits. This is a higher proportion of the total value of permits than for Scenario 1 because the energy intensive loads form a higher proportion of the total load in this scenario than in other

scenarios (because of the assumptions that most of the energy efficiency in this scenario would occur in non-energy intensive sectors).

- For Scenario 2, about $11.1 billion, or about 21% of the total value of permits.

The amount of compensation could be less to the extent that abatement policies are enacted in the countries of their trading competitors. Under an international agreement to curb emissions, some of these industries (such as non-ferrous metals) may even benefit through increased demand for their product and thus may not need compensation. Furthermore, to the extent that emission abatement costs are lower in Australia than in other countries, then the amount of compensation required would be less. This is because competing plant in overseas jurisdictions may end up experiencing a higher increase in electricity costs.

The amount of compensation required in the first 10 years of the study period is also significantly lower due to the lower emissions caps and the lower permit prices that result under the three scenarios modelled.

3.5 Generation mix

The change in the mix of generation is highlighted in Figure 3-9, which shows the change in capacity by technology type for Scenario 1. A major feature of the results is that there is a large increase in renewable generation capacity, reaching up to 2,400 MW. Higher wholesale electricity prices[10] by 2020, coincides with a reduction in the cost of renewable technologies, encouraging additional biomass and wind generation. Some hydro-electric facilities are also upgraded[11].

There is a decline in black coal capacity as new black coal capacity that was coming on-stream in 2016 to 2019 in the business as usual scenario are displaced by new high efficient natural gas plant. Capacity of black coal plant is also lower after 2020 because the increase in energy efficiency induced by emissions trading lowers demand growth and delays the need for new black coal plant by about one or two years.

Brown coal capacity appears to increase over a period from 2022 to 2026. This is due to the fact that the emissions permit price is above levels required to encourage IGCC with carbon capture and storage to come on stream one or two years earlier than required[12].

Natural gas fired generation capacity increases slightly during the study period. New gas fired generation plants are being selected in all markets under business as usual in the period to 2020. In the NEM, the market simulations indicate the need for intermediate plant in the period to 2020, for which gas-fired generation is the economic choice, or to meet the Queensland GEC target. With emissions trading, the new gas plant selected

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[10] Note: Wholesale market prices reported in Table 3.4 are on a time weighted average basis. The actual prices received by some renewable generators will be significantly higher than time weighted average prices if their generation is concentrated in peak price periods.

[11] Mainly upgrades of pre-1990 hydro-electric facilities in Tasmaina other than the Poatina Power Station.

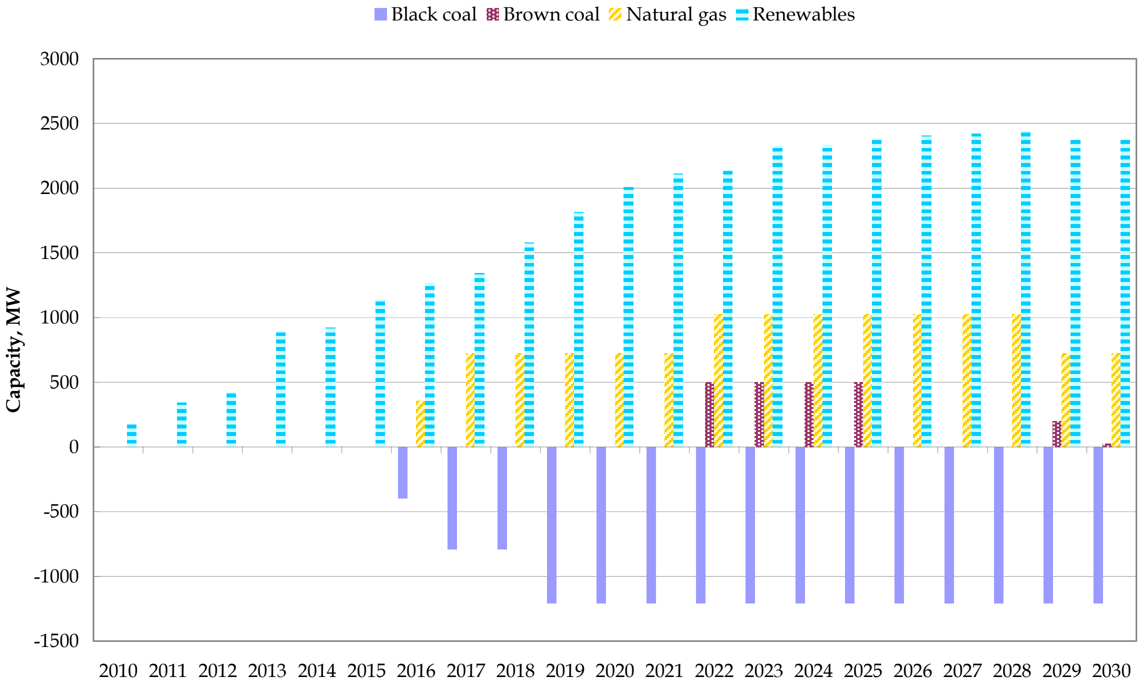
[12] The cost of carbon capture and storage for brown coal IGCC plant are assumed to fall from about $32/t CO_2e in 2020 to around $25/t CO_2e in 2030. Permit prices in most scenarios are above this level during this period.

change role to operate at higher load duties. In the SWIS, natural gas fired cogeneration plant are the preferred plant even for base load duty. In any case, no new base load plant are required in the SWIS until well into the next decade as a result of a surplus of new base load capacity entering the market over the next three years. Natural gas is also the preferred option even without emissions trading in the Northern Territory, north Queensland and South Australia.

The only additional gas fired generation under Scenario 1 occurs in south east Queensland, where two new combined cycle plant replace brown field expansions of black coal plant in the Surat Basin.

Beyond 2020, projected higher gas prices and the projected commercialisation of IGCC technology burning coal leads to a swing back towards coal-fired plant as the preferred technology, especially in Queensland, NSW and Victoria. The preference for IGCC technology over gas fired plant is maintained with the emissions trading under the targets examined because of the low emissions intensities of these technologies (relative to conventional coal generation technologies) and the potential to include carbon capture and storage at the permit prices under each target.

Figure 3-9: Change in generation capacity mix, Scenario 1 versus BAU

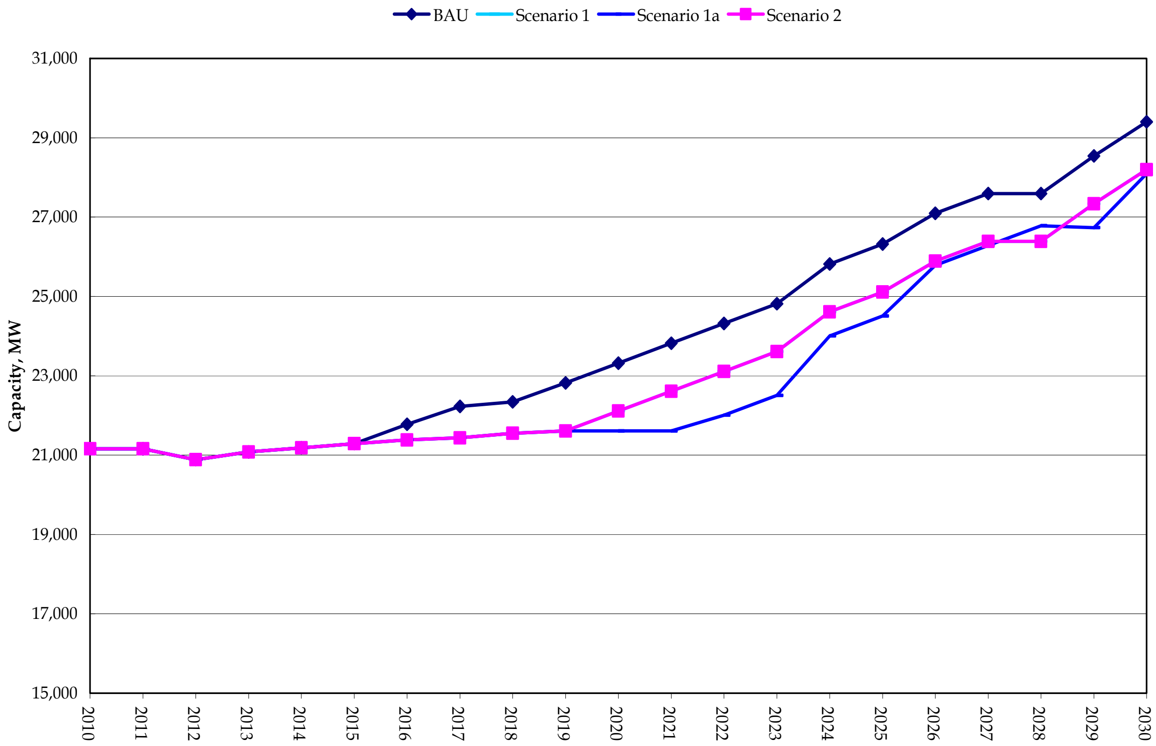


These trends are generally found to occur under all three emission trading scenarios. Table 3-8 indicates the amount of new generation capacity by technology type in 2015, 2020 and 2030. There are two key points to emerge from the results:

- Investment in new coal-fired capacity is lower under emissions trading. This mainly arises over the next decade, and occurs when new natural gas fired capacity replaces mainly new black coal fired generation in the next decade. There is also a substantial increase in the level of renewable energy capacity entering the market as a result of the higher electricity prices. Note that the level of brown and black coal fired capacity is the same in both Scenario 1 and Scenario 2. In both scenarios, no new coal plant is required after 2020, by which time it is the preferred technology even with a high emission price due to the increased cost of natural gas.

- However, the level of black coal and brown coal capacity still increases even with emissions trading. It just increases at a lower rate (see Figure 3-10). This result depends crucially on the assumptions as to when the cost of IGCC technology with carbon capture and storage is competitive relative to conventional coal technologies. It has been assumed that the cost of carbon capture and storage decreases to a point where IGCC plus carbon capture and storage is economic at carbon prices of between \$25/t CO_2e and \$35/t CO_2e in the period after 2020.
- Also note that the high levels of energy efficiency in Scenario 1a has the largest impact on the timing and amount of new capacity. With high levels of energy efficiency (see Scenario 1a), the lower level of demand results in less need for new plant. In the case of natural gas fired plant, the high levels of energy efficiency in this scenario results in the impact of emissions trading on selection of new gas plant being offset by the lower level of demand resulting in less natural gas fired capacity relative to the business as usual scenario.

Figure 3-10: Level of generation capacity
(a) Black coal



(b) Brown coal

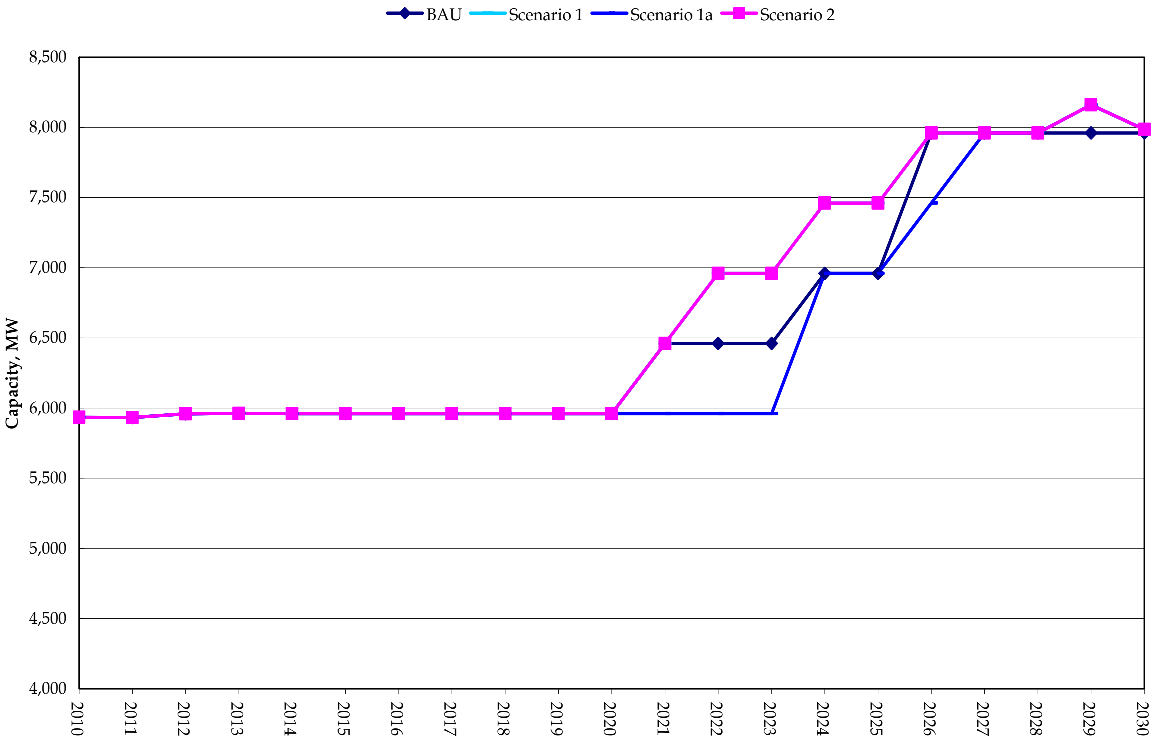

BAU
Scenario 1
Scenario 1a
Scenario 2
Capacity, MW
8,500
8,000
7,500
7,000
6,500
6,000
5,500
5,000
4,500
4,000
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030

Table 3-8: Generation capacity, MW

Technology	Unit	BAU			Scenario 1			Scenario 1a			Scenario 2		
		2015	2020	2030	2015	2020	2030	2015	2020	2030	2015	2020	2030
Black coal													
Queensland	MW	8,014	9,221	11,721	8,014	8,014	10,514	8,014	8,014	10,909	8,014	8,014	10,514
New South Wales	MW	11,494	12,310	15,810	11,494	12,310	15,810	11,494	11,810	15,310	11,494	12,310	15,810
South Australia	MW	707	707	485	707	707	485	707	707	485	707	707	485
Western Australia	MW	1,073	1,078	1,387	1,073	1,078	1,387	1,073	1,078	1,387	1,073	1,078	1,387
Total	MW	21,289	23,318	29,404	21,289	22,110	28,197	21,289	21,610	28,092	21,289	22,110	28,197
Brown Coal													
Victoria	MW	5,960	5,960	7,960	5,960	5,960	7,986	5,786	5,960	7,986	5,960	5,960	7,986
Natural gas													
Queensland	MW	2,482	3,182	3,782	2,482	3,912	4,512	1,638	2,682	3,782	2,482	3,912	4,512
New South Wales	MW	558	1,209	2,186	558	1,209	2,186	558	558	1,860	558	1,209	2,186
Victoria	MW	2,193	3,493	3,493	2,193	3,493	3,493	1,463	1,763	3,493	2,193	3,493	3,493
Tasmania	MW	262	332	632	262	332	632	227	332	632	262	332	632
South Australia	MW	1,855	1,855	2,775	1,855	1,855	2,775	1,855	1,855	2,775	1,855	1,855	2,775
Western Australia	MW	3,154	3,514	4,585	3,154	3,514	4,585	3,154	3,514	4,465	3,154	3,514	4,585
Northern Territory	MW	371	479	533	370	478	532	370	478	532	370	478	532
Total	MW	10,875	14,064	17,985	10,875	14,793	18,715	9,265	11,183	17,540	10,875	14,793	18,715
Renewables													
Queensland	MW	798	798	798	830	830	832	798	830	832	904	918	942
New South Wales	MW	3,821	3,821	3,821	4,010	4,200	4,314	3,821	4,010	4,119	4,050	4,207	4,227
Victoria	MW	809	809	809	1,088	1,229	1,293	818	1,109	1,160	1,168	1,260	1,334
Tasmania	MW	2,082	2,082	2,082	2,382	2,481	2,481	2,082	2,237	2,357	2,527	2,587	2,587
South Australia	MW	326	326	326	418	673	721	372	422	591	348	685	724
Western Australia	MW	266	310	290	266	491	609	256	256	236	268	492	611
Northern Territory	MW	0	0	0	0	0	0	0	0	0	0	0	0
Total	MW	8,102	8,146	8,126	8,994	9,904	10,251	8,146	8,863	9,295	9,266	10,150	10,425

Although there is not much change in capacity, there is substantial change in amount of generation by technology type (see Figure 3-11 and Figure 3-12). Coal fired generation is reduced by up to 30% with Scenario 1 and 37% with Scenario 2 compared with BAU. The largest absolute level reductions occur in NSW, although in proportional terms the largest reduction occurs in Western Australia where coal fired generation is effectively halved.

The reduction compared with BAU in coal fired generation is explained by:

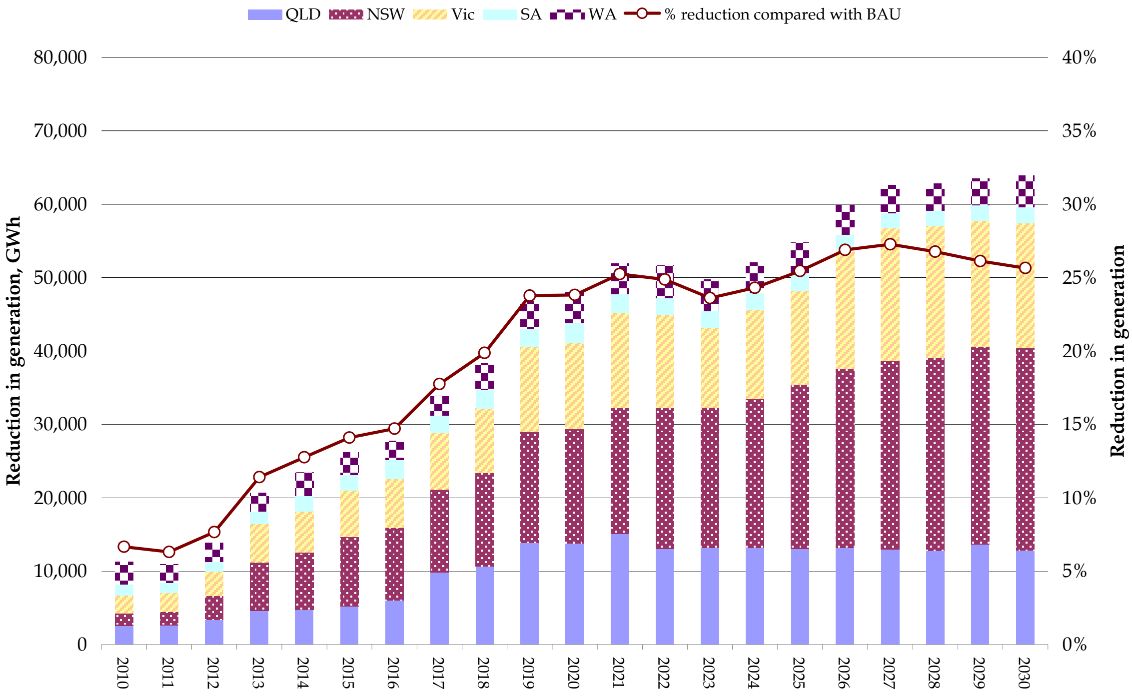
- The increase in gas-fired generation. The permit prices allow the higher cost coal-fired generation to be displaced by efficient gas-fired generation from combined cycle technologies. This factor wanes over time as gas prices increase.
- Lower electricity demand through energy efficiency improvements by end users. This accounts for one–fifth to one-third of the reduction in coal fired generation.
- An increase in the level of renewable generation as a result of substantial new capacity in renewable generation.

Although gas fired generation does increase overall, in some states (Victoria and South Australia) the level of gas-fired generation decreases as a result of the reduction in demand caused by increased energy efficiency by end-users and the displacement of generation from older gas-fired steam units.

Renewable generation is projected to increase overall. However, there is a reduction in hydro-electric generation in NSW and Queensland as a result of the reduction in generation from pumped storages associated with the Snowy Mountains Scheme and Wivenhoe. The profit margin on pumped storage operation is reduced with emissions trading as the cost of purchasing permits in off-peak periods (when high emissions intense coal plant set the price) increases more than the price received for selling energy in peak periods.

Figure 3-11: Reduction in coal fired generation

(a) Scenario 1 versus BAU



(b) Scenario 2 versus BAU

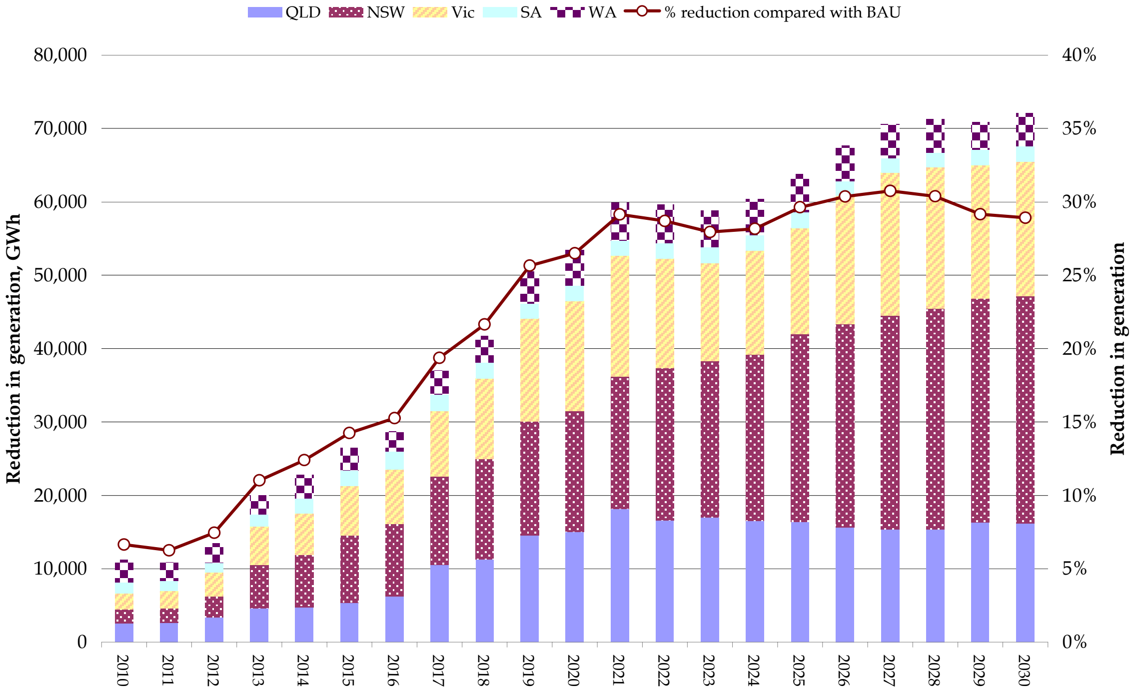
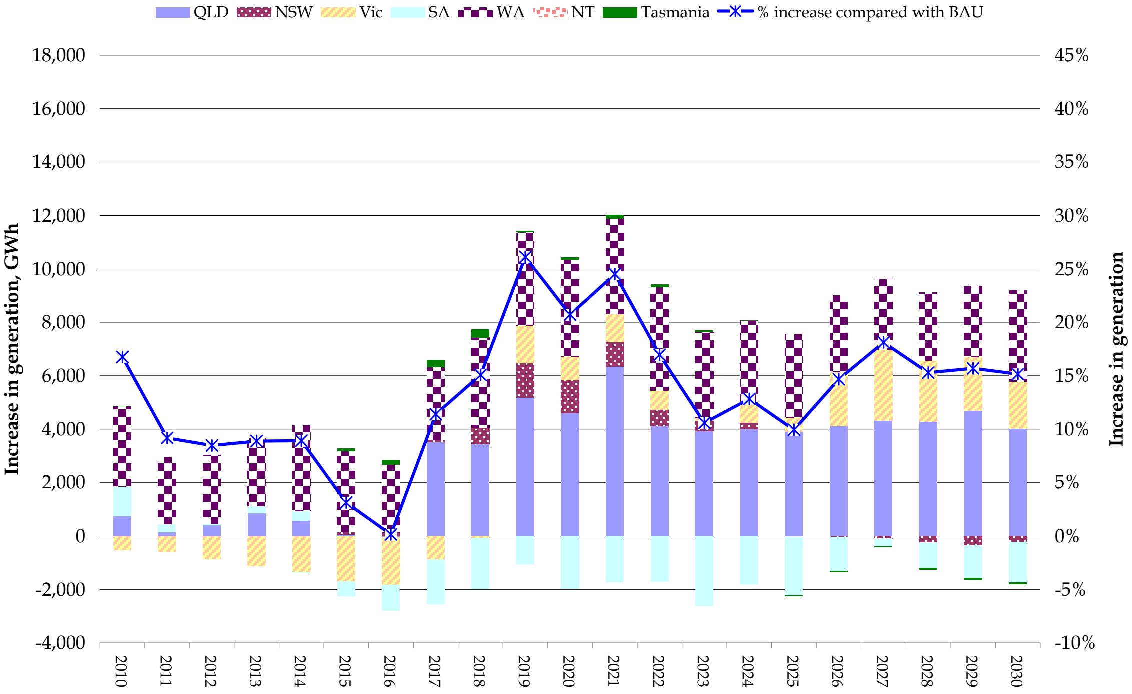
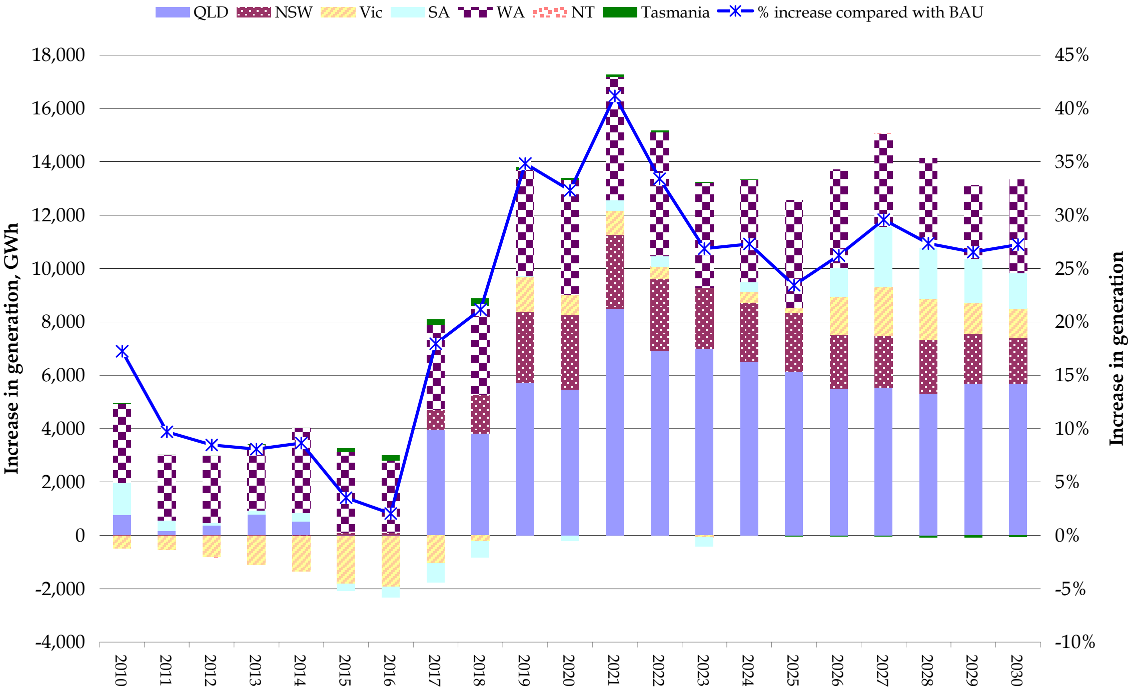


Figure 3-12: Increase in gas fired generation

(a) Scenario 1 versus BAU



(b) Scenario 2 versus BAU



3.6 Generator profitability

Indicative impacts on generator profitability are shown in Table 3-9. As expected, in the absence of any compensation, the operating profits of existing brown and black coal generators are likely to be reduced with the introduction of a carbon price through emissions trading. Almost every existing black and brown coal generating plant is projected to experience a reduction in profit. Renewable and some natural gas generators in contrast are projected to experience a significant increase in profitability.

The data in Table 3-10 consist of the sum of indicative change in profits for each generating unit by technology type. Losses represent a reduction in profit under emissions trading relative to business as usual conditions[13]. The actual losses may be lower as some generators in each technology type may make profits which offset losses made by other generating units. Losses incurred by existing generators have been calculated to be[14]:

- $29.2 billion for Scenario 1, which can be offset by allocating 70% of the total permits issued for the period 2010 to 2030 for free.
- $17.8 billion for Scenario 1a, which can be offset by allocating 61% of the total permits issued for the period 2010 to 2030 for free. This is likely to be an overestimate of the impact of emissions trading because some of the reduction in profit is due to the impact of reduced electricity demand brought about by the enhanced energy efficiency program assumed for this scenario.
- $31.5 billion for Scenario 2, which can be offset by allocating 71% of the total permits issued for the period 2010 to 2030 for free.

Even some gas-fired plants experience a reduction in profit. In the case of peaking plant, this is principally due to a reduction in peak demand due to energy efficiency (which reduces the volume of generation and leads to a lower net price received in peak periods after permit prices are deducted)[15]. In scenario 2, the impact of a high level of energy efficiency in reducing electricity demand also reduces the profitability of some existing combined cycle and cogeneration plant.

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[13] Profit in each year is equal to revenue from wholesale market sales (the sum of the product of expected pool price in each hour times the amount of generation sold in each hour) minus variable and fixed operating costs. The purchase costs of emissions permits are included as part of the variable cost. Losses reported in this section represent a reduction in the profit earnt either because of the purchase price of the permit and/or a reduction in the volume of generation.

[14] The losses have been calculated as the net present value of gross losses incurred by each generating unit, using a real pre-tax discount rate of 6%. A loss has been defined as a reduction in profit under emission trading relative to the profit made in the business as usual case

[15] Please note that for peaking plant, the estimates of the reduction in profit are especially indicative because their output is very hard to predict (being influenced by the impact on peak demand of variable weather conditions), and the numbers depend on prices over very short and uncertain quantities.

Table 3-9: Indicative impact on generator profitability, $M

	Qld	NSW	Vic	Tas	SA	WA	NT	Aust
Scenario 1								
Black coal	-5,543	-8,705	0	0	-449	-383	0	-15,079
Brown coal	0	0	-11,000	0	0	0	0	-11,000
Natural gas	-917	-644	-635	917	-127	1,042	8	-356
Liquid fuels	-125	-32	0	0	79	4	-2	-76
Renewables	62	800	1,071	2,879	-329	220	0	4,702
Total	-6,523	-8,581	-10,563	3,795	-826	882	6	-21,810
Scenario 1a								
Black coal	-3,761	-5,542	0	0	-135	-345	0	-9,783
Brown coal	0	0	-5,831	0	0	0	0	-5,831
Natural gas	-210	-280	-181	-73	-89	833	7	8
Liquid fuels	-96	-27	0	0	55	3	-2	-66
Renewables	-15	242	22	1,054	0	198	0	1,500
Total	-4,082	-5,607	-5,990	981	-168	689	5	-14,171
Scenario 2								
Black coal	-5,896	-9,037	0	0	-701	-436	0	-16,069
Brown coal	0	0	-11,489	0	0	0	0	-11,489
Natural gas	-905	-660	-644	1,152	-546	518	9	-1,076
Liquid fuels	-130	-32	0	0	-33	2	-2	-195
Renewables	267	181	267	4,397	0	258	0	5,370
Total	-6,663	-9,548	-11,866	5,549	-1,280	343	7	-23,459

Source: MMA analysis Profits and losses for Scenario 1a are estimates based on indicative impacts on existing generators with the energy efficiency program without emission trading.

Table 3-10: Losses incurred by existing generators (calculated for compensation purposes), by generating unit, $M

	Qld	NSW	Vic	Tas	SA	WA	NT	Aust
Scenario 1								
Black coal	-5,549	-8,733	0	0	-461	-383	0	-15,127
Brown coal	0	0	-11,000	0	0	0	0	-11,000
Natural gas	-1,154	-644	-491	-120	-325	-86	-13	-2,833
Liquid fuels	-126	-32	0	0	-37	-5	-2	-201
Renewables	-11	0	0	0	0	0	0	-11
Total	-6,840	-9,408	-11,491	-120	-823	-474	-15	-29,171
Scenario 1a								
Black coal	-3,866	-5,638	0	0	-179	0	0	-9,682
Brown coal	0	0	-5,831	0	0	0	0	-5,831
Natural gas	-450	-283	-416	-149	-57	-197	-11	-1,563
Liquid fuels	-116	-27	0	0	-23	-1	-5	-171
Renewables	-30	-20	-118	-243	0	-119	0	-530
Total	-4,462	-5,967	-6,365	-392	-258	-316	-17	-17,777
Scenario 2								
Black coal	-5,902	-9,066	0	0	-702	-435	0	-16,105
Brown coal	0	0	-11,489	0	0	0	0	-11,489
Natural gas	-1,213	-660	-645	-91	-717	-63	-14	-3,403
Liquid fuels	-130	-32	0	0	-133	-4	-2	-302
Renewables	0	-47	-108	-47	0	0	0	-202
Total	-7,246	-9,805	-12,243	-138	-1,552	-503	-16	-31,501

Source: MMA analysis. Note the estimates in this table differ from the previous table in that it includes on the sum of reduction of profits for each generating units. It does not include gains in profits by generating units.

However, the losses may be an overestimate of the true losses faced by many generating companies. Some generating companies have units that increase profits and units that have reduced profits. Other generators may have revenue streams protected by long term contracts. Based on portfolio of losses and gains, the losses to generators could reduce to:

- $17.6 billion for Scenario 1.
- $11.0 billion for Scenario 1a.
- $19.0 billion for Scenario 2.

Thus, basing compensation by portfolio could reduce the amount of compensation to generators by up to 30% to 40%.

The value of permits required to fully compensate generators could also be reduced if the net losses faced by generators over the time period of the scheme were taken into account. Some generators make losses in some years but profits in other years. Thus, again it may be considered appropriate that only net losses by these generators are compensated. Based on calculations where only net losses by each generating unit over the period from 2010 to 2030 are compensated[16], then the compensation would be around:

- $26.0 billion dollars instead of $29.2 billion for Scenario 1
- $15.7 billion dollars instead of $17.8 billion for Scenario 1a
- $29.0 billion dollars instead of $31.5 billion for Scenario 2

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[16] These losses are calculated by generating unit not by portfolios.

4 IMPLICATIONS

The analysis provides a number of important findings, with the key findings being:

- Substantial abatement is possible in the domestic action scenarios at a permit price of less than \$35/t CO_2e over the study period.
- Abatement in the period to 2020 is driven by fuel switching, additional energy efficiency and increased renewable generation. The potential for this level of abatement is relatively certain as they are based on known operating costs of existing generating plant. There is still some uncertainty over the rate of growth of electricity demand, but low cost abatement opportunities are likely to be available from fuel switching during this period.
- Beyond 2020, abatement and the cost of abatement are driven principally by the cost and rate of adoption of low emissions technologies. Of course, future costs of low emissions technologies are highly uncertain. This would suggest that a review of likely targets for the period beyond 2020 is warranted sometime next decade.

The impacts of emissions trading can be summarised as follows:

- Black coal generation is affected. In most scenarios, this is mainly reflected in reduced rates of growth in the short term. In the long term, there is an important role for coal fired generation if carbon capture and storage technologies can be developed at low cost and as gas reserves deplete.
- Brown coal generation is also affected. Even under emissions trading the long term outlook for brown coal generation remains strong as long as new low emissions technologies are developed and as gas prices in Victoria increase. Victoria has a comparative advantage in carbon storage relative to other States and so the brown coal sector could be supported in the long term under emissions trading. However, existing brown coal generators are likely to suffer reduced generation due to their high emissions intensity and will experience reduced profitability unless they are compensated. Some effort in developing technologies at lowering emissions at existing brown coal facilities could ameliorate the impacts.
- Gas generation increases in most scenarios, except where a large amount of energy efficiency occurs.
- Renewables clearly expand with emissions trading.

The analysis also indicates that the cost of emissions trading will be smaller if:

- Supporting policies for energy efficiency were adopted.
- Development of low emissions technologies was supported by the Government and industry.

- Low cost offset options are included.

There are winners and losers from adoption of emission trading. Both generators and energy intensive trade exposed customers could face substantial losses in the absence of compensation. Sufficient permits are likely to be available to compensate generators and energy intensive customers in all the scenarios modelled. There is also likely to be surplus permit for auctioning, which can be used to compensate other customers (see Table 4-1).

Table 4-1: Indicative revenue and compensation levels, $M

	2010 to 2020	2021 to 2030	2010 to 2030
Scenario 1			
Customer losses	3,634	5,910	9,545
Generator losses	15,990	13,181	29,171
Surplus permits	2,982	-295	2,687
Total revenue	22,606	18,797	41,403
Scenario 1a			
Customer losses	3,404	5,320	8,724
Generator losses	7,702	10,075	17,777
Surplus permits	2,132	564	2,696
Total revenue	13,238	15,959	29,197
Scenario 2			
Customer losses	4,013	7,101	11,113
Generator losses	17,000	14,501	31,501
Surplus permits	2,788	-805	1,983
Total revenue	23,800	20,797	44,597

Source: MMA analysis. All values are in mid 2006 dollar terms and represent net present values of revenue and cost streams discounted using a 6% real pre-tax discount rate.

The indicative estimates of the level of compensation presented in the above table imply perfect foresight of future events in both the business as usual and emissions trading worlds. Clearly with the sums of money potentially involved, rigorous and robust analysis would be required to determine compensation levels.

Much of the analysis has been concerned with impacts. An indication of the economic efficiency cost of emissions trading is to look at the additional resource costs incurred. That is, the additional capital, fuel and operating costs incurred as a result of emission trading. The net present values of the additional resource costs are shown in the following table. The estimates range from $2.2 billion for Scenario 1 to $3.7 billion for Scenario 2. There is a reduction of the resource cost in Scenario 1a, but this mainly reflects the benefits of a higher level of energy efficiency deferring the need for new capital expenditure on generating plant and for reducing fuel use in generation.

Table 4-2: Resource costs of emission trading, $ million

	2010 - 2020	2021 - 2030	2010 - 2030
Scenario 1	734	1,505	2,239
Scenario 1a	-654	7	-647
Scenario 2	682	2,979	3,661

Calculated using a discount rate of 6%. Does not include the additional costs of adopting energy efficiency options and embedded generation or the additional resources expended in increasing plantations for biosequestration

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 MMA's National Electricity Market model. This model is based on the 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 the NEM regions. In addition, MMA partitions Queensland into four 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 such as Newport and Hazelwood in Victoria.

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

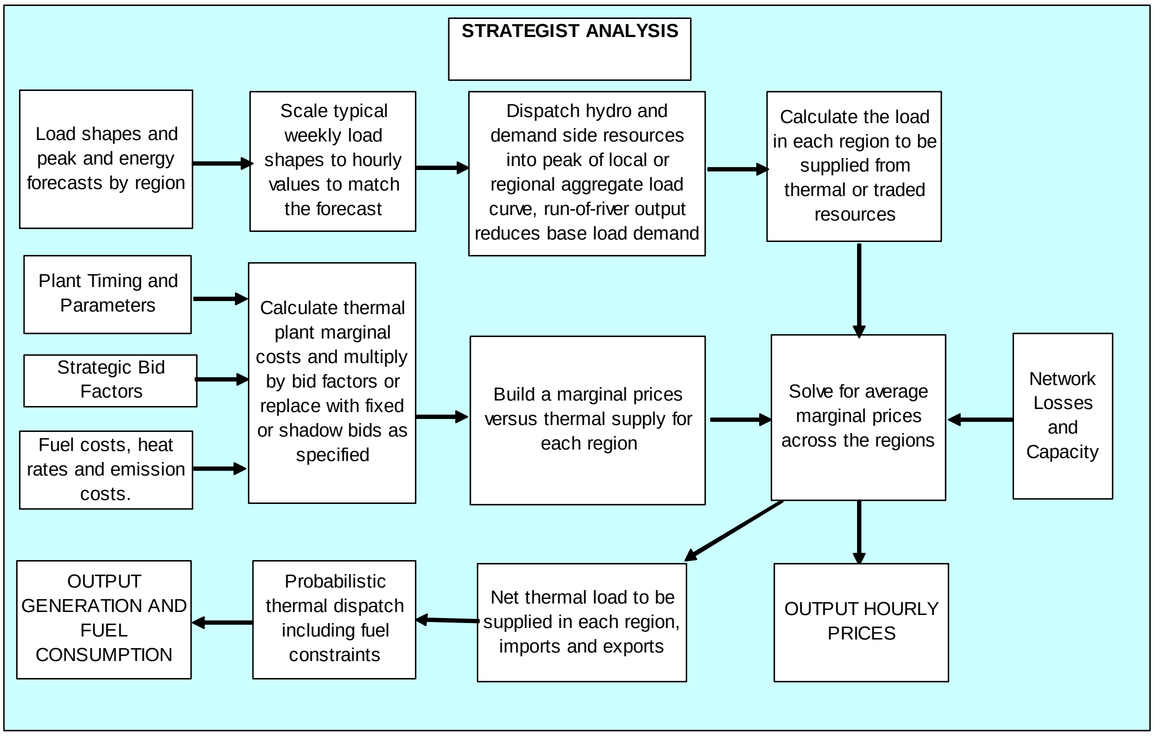
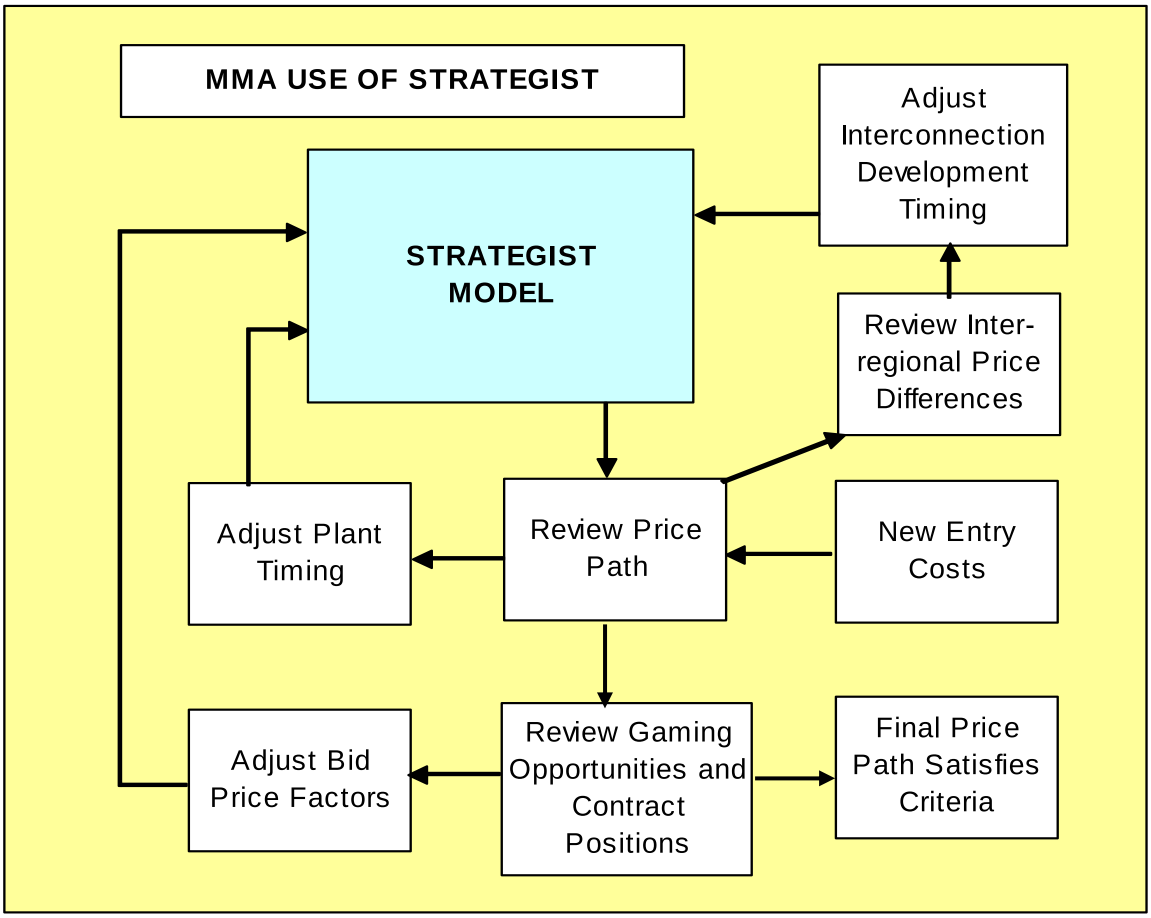


Figure A- 2: MMA Strategist Modelling Procedures



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, having regard to all possible thermal plant failure states and their probabilities. The prices are solved across the regions of the NEM 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. Constraints can be varied hourly if required and such a method is used to represent variations in the capacity of the Heywood interconnection, between Victoria and South Australia, which have been observed in the past when it was heavily loaded.

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.

A.4 Base Assumptions for the NEM

The business as usual case reflects the most probable prices given the current state of knowledge of the market. Common features of the business as usual case and other scenarios include:

- The Queensland Cleaner Energy Policy continues until 2020. In the business as usual scenario, the NSW Greenhouse Gas Abatement Scheme is assumed to cease operation in 2012. This is to allow proper calculation of the economic costs of introducing emissions trading without the results being confounded by the impacts of other large scale abatement schemes. In the emissions trading scenarios the NGGAS scheme was assumed to cease at the start of 2010.
- The Victorian Renewable Energy Target (VRET) was not assumed to proceed in all scenarios modelled, due to uncertainty over the final structure of the scheme.
- PNG/Timor Sea gas supply delivered to Queensland for new power generation and for supply to southern and eastern seaboard markets from July 2012.
- Generators behaving rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry.
- Infrequently used peaking resources are bid near VoLL.
- The generator bidding profiles reflect generator contracting levels and assumed revenue targets, based on MMA's benchmark study for 2004 calendar year.
- Moomba to Sydney gas pipeline tariffs are consistent with the July 2002 submission to the ACCC by the Australian Pipeline Trust.
- Basslink commences operation in April/May 2006. Commissioning of Basslink commenced on 1 April 2006.
- The Commonwealth Government's policy to achieve 2% additional renewable energy by 2010 has been implemented as a 9500 GWh target with a maximum penalty for non-performance of $40/MWh post-tax which corresponds to $57/MWh pre-tax.
- The commissioning of Snowy Hydro's Laverton North open cycle gas fired power station in mid 2006.
- The commissioning of Kogan Creek as a base load generator in Queensland at the beginning of September 2007 (the SOO indicates commissioning in late August).
- The retirement of Swanbank B units in 2011.
- The commissioning of 2 150 MW gas turbines at Braemer in June 2006, with the third 150 MW unit being available in November 2006 for the 2006/07 summer.
- A 170 MW VIC->SA upgrade on the Heywood interconnector in July 2009 to augment supply to South Australia.
- A series of network augmentations as required (see Section A.4.8 below)

A.4.1 Market structure

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

- Existing Government owned NSW generators remain under the current structure in public ownership;
- Existing Government owned Queensland generators remain in public ownership
- The South Australian generators continue under existing portfolio groupings (Optima in the TRUenergy portfolio and Synergen in the International Power portfolio with Pelican Point and Hazelwood Power)

A.4.2 Marginal costs

The marginal costs of thermal generators consist of the variable costs of fuel supply including fuel transport plus the variable component of operations and maintenance costs. The indicative variable costs for various thermal plants are shown in Table A.1. For coal plant, the marginal cost of fuel is based on the opportunity cost of the fuel. In the case of power stations supplied from mines not owned by them, the opportunity cost reflects forecasts of the export parity price of coal (as published each year by ABARE). We also include in the marginal fuel costs for brown coal the net present value of changes in future capital expenditure that would be driven by fuel consumption for open cut mines that are owned by the generator. This applies to coal in Victoria and South Australia.

Table A- 1: Indicative Average Variable Costs for Thermal Plant ($June 2005)

Technology	Variable Cost $/MWh	Technology	Variable Cost $/MWh
Brown Coal – Victoria	$6 - $10	Brown Coal – SA	$17 - $23
Gas – Victoria	$36 - $54	Black Coal – NSW	$17 - $20
Gas – SA	$30 - $90	Black Coal - Qld	$12 - $20
Oil – SA	$175 - $220	Gas - Queensland	$21 - $57
Gas Peak – SA	$80 - $115	Oil – Queensland	$200

Our estimates of marginal cost are higher than those estimated by ACiL Tasman in a report for NEMMCO. The difference between MMA numbers and ACiL Tasman numbers depend on what your view is of fuel costs: contract fuel prices can be considered a fixed cost (in which case the marginal cost is very low) or as an opportunity cost if there is an alternative market for the fuel (such as a spot market for gas). We consider the latter approach to be more appropriate for most power stations except for existing mine mouth coal stations. We have always taken comfort of our SRMC estimates based on the close alignment of our model and actual bids and pool prices in off peak periods, when gaming is likely to be less rife. With gaming, the outcome is not likely to be greatly different from our current results.

A.4.3 Plant Performance and Production Costs

Thermal power plants are modelled with planned and forced outages with overall availability consistent with indications of current performance. Coal plants have available capacity factors between 86% and 95% and gas fired plants have available capacity factors between 87% and 95%.

Table A- 2: Costs and Performance of Thermal Plants in 2005

Plant	No Units	Sent Out Capacity	Available Capacity factor	Full Load Heat Rate	Variable O&M	Variable Fuel Cost $/GJ	Total Variable Cost $/MWh
Tasmania							
Bell Bay	2	226.9	92.41%	10.9	$2.39	$3.72	$42.76
New GT	0	0.0	92.03%	11.5	$3.45	$5.12	$62.33
Victoria							
Loy Yang A	4	1899.0	92.85%	13.0	$0.96	$0.42	$6.41
Loy Yang B	2	920.0	92.49%	12.8	$0.96	$0.42	$6.33
Yallourn W	4	1368.0	88.53%	13.6	$1.19	$0.43	$7.06
Hazelwood	8	1472.0	90.45%	14.8	$2.39	$0.55	$10.58
Anglesea	1	143.5	94.37%	15.1	$1.19	$0.12	$3.05
Energy Brix	3	136.2	86.58%	15.4	$2.39	$0.75	$13.88
Newport(1)	1	484.5	92.97%	10.3	$2.39	$3.31	$36.62
Jeeralang A	4	230.8	94.96%	13.7	$7.16	$3.21	$51.36
Jeeralang B	3	253.7	94.96%	12.8	$7.16	$3.21	$48.46
Bairnsdale	2	89.6	93.23%	11.5	$3.58	$3.86	$48.02
Valley Power (EME)	6	334.3	94.96%	13.7	$7.16	$3.21	$51.36
AGL Somerton	4	151.2	87.51%	13.5	$2.39	$3.31	$47.13
Laverton North	2	310.4	93.95%	11.6	$3.58	$4.36	$54.37
South Australia							
Northern	2	494.9	93.56%	11.4	$2.32	$1.29	$17.02
Playford B (After refurbishment)	4	222.0	83.66%	15.0	$3.48	$1.29	$22.85
Torrens Island A	4	478.8	87.51%	10.8	$7.16	$5.22	$63.55
Torrens Island B	4	782.8	87.51%	10.5	$1.79	$2.75	$30.62
Pelican Point	1	462.6	93.23%	7.7	$2.39	$3.42	$34.30
Mintaro 1	1	85.6	89.01%	16.0	$7.16	$7.54	$88.91
Dry Creek	3	139.3	89.01%	14.0	$7.16	$7.54	$112.55
Ladbroke Grove	2	83.6	92.03%	10.1	$5.97	$2.70	$33.11
Osborne	1	187.4	93.95%	10.7	$2.32	$3.67	$41.41
Snuggery	3	62.7	87.91%	15.0	$7.16	$14.11	$218.63
Port Lincoln	2	46.8	91.33%	12.1	$7.16	$14.11	$177.36
Quarantine	4	91.5	89.01%	10.4	$7.48	$3.67	$45.52
Hallett	8	191.0	89.11%	19.4	$8.18	$3.67	$79.49
Angaston	24	39.8	94.15%	9.0	$10.25	$7.54	$78.41
NSW							
Bayswater	4	2592.7	94.69%	10.1	$2.39	$1.42	$16.83
Eraring	4	2481.6	92.79%	9.8	$2.39	$1.68	$18.85
Mt Piper	2	1240.8	91.33%	10.0	$2.27	$1.50	$17.23
Vales Point	2	1240.8	88.53%	10.1	$2.99	$1.72	$20.44
Wallerawang	2	940.0	86.61%	10.7	$3.58	$1.42	$18.89

Plant	No Units	Sent Out Capacity	Available Capacity factor	Full Load Heat Rate	Variable O&M	Variable Fuel Cost $/GJ	Total Variable Cost $/MWh
Liddell	4	1955.2	93.79%	11.2	$2.16	$1.42	$18.10
Munmorah	2	576.0	83.21%	11.2	$2.37	$1.55	$19.78
Smithfield	1	170.0	92.33%	10.0	$4.54	$3.76	$33.04
Hunter Valley GTs	2	50.7	88.81%	23.4	$8.24	$14.11	$337.83
Tullawarra	1	400.0	94.15%	7.4	$3.00	$3.50	$28.90
Pt Kembla (New)	1	193.9	92.03%	7.1	$3.00	$0.50	$6.55
Munmorah GT	4	149.5	92.19%	11.1	$2.00	$3.60	$41.96
Queensland							
Barcaldine CC	1	50.0	91.33%	8.0	$3.58	$3.72	$33.42
Callide B	2	658.0	86.80%	9.9	$1.72	$1.39	$15.50
Callide C	2	864.8	90.73%	9.0	$1.19	$1.40	$13.80
Collinsville	5	174.8	89.43%	13.7	$2.39	$1.71	$25.84
Gladstone	6	1579.2	91.19%	10.2	$1.04	$1.62	$17.51
Stanwell	4	1353.6	92.35%	9.9	$0.96	$1.43	$15.15
Tarong	4	1316.0	92.35%	10.0	$0.99	$1.09	$11.83
Tarong North	1	416.4	91.33%	9.0	$0.99	$1.20	$11.76
Swanbank B	4	467.5	79.65%	10.7	$2.39	$1.53	$18.66
Swanbank E	1	373.5	94.15%	8.1	$2.39	$3.42	$30.09
Roma (Boral)	2	67.7	87.51%	13.5	$4.78	$3.72	$55.00
Mackay GT	1	32.8	94.25%	13.5	$9.55	$14.11	$1,033.05
Yabulu CCGT	1	230.9	94.25%	11.4	$2.39	$3.16	$38.32
Mt Stuart GT	2	292.5	94.25%	13.8	$4.78	$14.11	$199.17
Oakey GT	2	318.4	94.25%	11.5	$4.78	$4.65	$58.26
Millmerran	3	1185.4	91.33%	9.9	$1.07	$0.66	$7.85
Braemar	3	477.6	94.15%	11.1	$4.78	$3.52	$43.79
Kogan Creek	1	717.2	91.33%	10.2	$1.07	$0.66	$7.79

Sources: Historical data published by NEMMCO, the AGO and in annual reports of the generators.

Emissions factors for each plant are modelled on a fuel basis (that is, kt CO_2e/PJ fuel consumed). The emissions factors for each generating unit are equal to the factors assumed in the latest edition of the National Greenhouse Gas Inventory as published by the AGO.

A.4.4 Medium Term Maintenance Outages

Plant maintenance outages for the medium term are modelled by attempting to reconstruct the MTPASA "maximum available capacity" sequence for each NEM region that is presented on the www.erisk.net website. This sequence details the maximum capacity planned to be available for each day over the following 18 months. A decrease in the sequence indicates that a generator in the region has been scheduled for maintenance, whereas an increase indicates a generator coming back online after its scheduled maintenance. This approach is clearly more accurate than merely applying a generic maintenance outage rate for each generator over the period in question.

The first step in approximating the MTPASA sequence is to match its initial value by observing current generation patterns of generators to determine the likely candidates presently undergoing maintenance. An algorithm was then developed to minimize the error between MMA's "maximum available capacity" sequence and that reported on the Erisk website, by cycling through all feasible outage sequences of generators one at a time and selecting the most optimal sequence. The accuracy of MMA's synthesized sequence varies considerably from region to region, since each region has different maintenance outage patterns. For example, the privatized generators in Victoria undergo frequent maintenance but for very short periods of time, presumably in an attempt to maximize their availability. This behaviour is significantly different to that in other regions where state-owned generators are maintained less frequently.

A.4.5 Committed and planned entry

The recently developed power projects and mothballed plant are shown in more detail in Table A- 3. The table shows the currently mothballed or reserve capacity in the NEM and the new projects which have been committed for completion within the next four years. It also shows other projects for which planning is well advanced. Torrens Island A is not shown as mothballed because all units are generally available to operate. The fourth Liddell unit is also available to operate although it uses operating staff from Bayswater Power Station and therefore is only operated during a Bayswater unit outage.

In Victoria, Snowy Hydro has commenced the development of 312 MW of peaking capacity at Laverton North. This project was expected to be commercialised in time for the 2005/06 summer, however, delays have meant that this project is now unlikely to be ready before mid 2006.

Origin Energy has recently announced that it is seeking environmental approvals to build a gas-fired power station of up to 1000 MW in Western Victoria, near the township of Mortlake. Origin is also seeking to build a similar plant in Spring Gully, South-east Queensland. The timeframe for these developments is highly uncertain, with a decision to proceed to construction not expected until mid 2006 and accordingly we have not specifically provided for these developments in our model.

Delta Electricity is considering projects in NSW including 600 MW of open cycle plant at Munmorah Power Station to use the existing transmission infrastructure. These developments are considered as new entry options in our modelling, and are included as needed.

Table A- 3: Mothballed Capacity and Recently Developed New Plants in the NEM

Power Plant	Generated Capacity (MW)	Region	Service Date	Status
Swanbank A	408	South Qld	Retired	Retired in June 2002. Units have been decommissioned and removed.
Callide A	120	Central Qld	Originally intended to be refurbished	Mothballed in April 2002. Now in indefinite dry storage.
Liddell	515	NSW	Reserve	Currently 3 out of the 4 units are dispatched at one time when Bayswater is fully available, with all 4 units being operable
Munmorah	2 X 300	NSW	Reserve	Both 300 MW units are operable at short notice when other Delta Electricity units are unavailable
TOTAL Reserve	**1643**			
Basslink	480/600	Vic/Tas	Apr/May 2006	480 MW rated capacity, 600 MW Short-term capacity
Laverton North	312	Vic	Mid 2006	Delays during construction have pushed completion date back until after summer 05/06.
Kogan Creek	755	South Qld	Sep 2007	Under construction
Wambo Braemar	3 X 150	Qld	Jun 2006 Jun 2006 Nov 2006	Intermediate gas fired generation. All units available by June 2006.
Braemar stage 2	3 x 150	QLD		OCGT advanced proposal
Wagga Wagga	3 X 150	NSW		OCGT advanced proposal
Tallawarra	400	NSW	Oct 2008	Combined-cycle gas turbine
Townsville South	380	QLD	Nov 2010	AGL's gas-fired power station in Qld North. Commencement date to correspond with arrival of PNG gas into Townsville
Quarantine upgrade	78	SA	Nov 2009	Expansion of Quarantine Power Station from single cycle to a 170MW CCGT – advanced proposal
Total Planned	**3,755**			
TOTAL	5,398			Includes reserve, new and prospective developments with advanced proposal status.

Planned decommissioning of plant is assumed to proceed as planned. This includes Swanbank A, which is assumed to be decommissioned at the end of 2011. Playford is also assumed to be decommissioned in 2025, as the local coal deposit is exhausted.

A.4.6 Plant Upgrading

Loy Yang Power has announced its intention to increase the capacity of Loy Yang A up to 2,200MW with some units rated at 580 MW. Macquarie Generation has announced plans to progressively fit the Liddell units with new high-pressure and intermediate-pressure turbines, increasing each units' capability by 10 MW. The upgrades will increase the Liddell capacity to 2,080 MW. Snowy Hydro has indicated that it intends to replace the turbine runners at Murray 2 and Tumut 3. As a result, Murray 2 plant capacity will increase from 550 MW to 620 MW by 2007/08 and Tumut 3 plant capacity will increase from 1,500 MW to 1,650 MW in 2008/09.

Delta electricity has publicly announced plans to upgrade the Mt Piper units, increasing total plant capacity from 1320 MW to 1500 MW. Similar upgrades would be possible for the Eraring and Bayswater units, increasing the capacity of the units to 750MW. We have assumed upgrades at Bayswater, although by only about 50 MW per unit. For Eraring, we assume upgrades to 750 MW per unit but we still apply the same derating in summer to mimic the current operating constraints due to lake temperature. These upgrades have been included as new capacity options in the expansion plan, with an incremental cost of about $500/kW.

A.4.7 Timing of new entry

After selecting new entry to meet NEMMCO's minimum reserve criteria, MMA's pool market solution may indicate when prices would support additional new entry under typical market conditions and these are included in the market expansion if required. Cost and financing assumptions used to develop the new entry prices are provided in Table A-4.

The capacity factors in Table A- 4 are deliberately high to allow us to approximate a time-weighted new entry price in each State that can rapidly be compared to the time-weighted price forecasts to determine whether or not new entry would be encouraged to enter the market. These capacity factors do not necessarily reflect the levels of duty that we would expect from the units. The unit's true LRMC measured in $/MWh is higher than this level. For example, we would be more likely to find a new CCGT operating in Victoria with a capacity factor of around 60% to 70% rather than the 92% as indicated in the table. Ideally, in determining the timing of new entry of such a plant we would compare the new entry cost of a CCGT operating at this level against the time-weighted prices forecast in the top 60% to 70% of hours.

However, as emissions penalties (in the form of the price to purchase a permit) are imposed, the optimal level of operation of a CCGT could rise and there will be some permit price at which it could become preferred as a base load plant. The optimal level of operation of all plant under emissions trading scenarios is determined by the simulation models of the electricity markets.

Table A- 4: New Entry Cost and Financial Assumptions ($ June 2005)

	Type of Plant	Capital Cost, $/kW	Max Capacity Factor	Fuel Cost, $/GJ	WACC (pre-tax), % real	Interest Rate on Debt, % nominal	Debt Level
SA	CCGT	1,131	93%	3.50	8.31%	8.5%	60%
Vic	CCGT	1,069	92%	3.20	8.31%	8.5%	60%
NSW	Black Coal	1,645	90%	1.22	8.31%	8.5%	60%
Qld	Black Coal	1,588	90%	0.82	8.31%	8.5%	60%

Note: Capital cost estimates are based on recent data (Gas Turbine World in the case of CCGTs and IGCC, recent tenders/announcements in Australia and elsewhere, and some international data for coal plant). We are reasonably confident on the gas and IGCC data, but less confident on data on capital cost for supercritical plant. Fuel prices are average delivered prices for each state for the 2005 year. These prices may vary by location within each State and over time.

A.4.8 Interconnections

Assumptions on interconnect limits are shown in Table A.5 and their current operating levels are illustrated in Figure A.3. These limits are based on the maximum recorded inter-regional capabilities for 2004/05. The actual limit in a given period can be much less than these maximum limits, depending on the load in the relevant region and the operating state of generators at the time. For example, in the case of the transfer limit from NSW to Queensland via QNI and Directlink, the capability depends on the Liddell to Armidale network, the demand in Northern NSW, the output from Millmerran, Kogan Creek and Wambo Braemar, and the limit to flow into Tarong[17]. During the summer of 05/06 NEMMCO estimates the combined northward capability on QNI and Directlink to be approximately 280 MW, and by 2007/08 this limit is estimated to be negative, implying that the limits are forcing QNI to export into NSW. Over time we expect that the constraints for power flow into Queensland would be relieved so that new generating capacity in the south-west can support the Brisbane area. These constraints are formulated in a simplified way in the Strategist model.

There are a number of possible interconnection developments being considered including:

- An upgrade of the existing Victoria to South Australia export limit from 460 MW to 630 MW by additional transformation at Heywood Terminal Station and possibly series compensation on the Tailem Bend - South East 275 kV lines (augmentation reference number 34 and 11 in the 2005 SOO)

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[17] There is currently expected to be a limit of about 900 MW for flow into Tarong. This is not a fixed limit and could be increased with additional load shedding in Queensland.

- Construction of a new transmission line from Middle Ridge to Greenbank, installation of a second transformer at Middle Ridge and upgrades to the existing transformer, to collectively increase northward flow on QNI by 700MW and increase the Tarong limit (from Tarong to Queensland South) by 450MW (augmentation reference number 23 in the SOO)

- Network augmentation through series compensation in South East Queensland to offset reductions in transfer capability following commencement of Kogan Creek (augmentation reference number 5 in the SOO)

- Works to maintain Directlink's export capability to Queensland (augmentation reference number 2 and 3 in the SOO)

- 100 MW increase in line rating on QNI in both directions through thermal rating upgrade of the Armidale – Tamworth 330 kV line (augmentation reference number 6 in the SOO)

- Relaxation of some constraints affecting southerly flow on QNI by installing a phase angle regulator to prevent overloading on the Armidale – Kempsey 132 kV line (augmentation reference number 4 in the SOO)

- A 600 MW upgrade of the Snowy to Victoria transmission link over time which would enable additional imports from Snowy/NSW into Victoria. The first 400 MW stage was completed by VENCorp as the regulated SnoVic facility in December 2002. This option has been further developed in the latest NSW Planning Statement to include options with augmentation of 180 MW and then up to 2500 MW total transfer from Snowy to Victoria.

Table A- 5: Interconnection Limits – based on maximum recorded limit in 2004/05

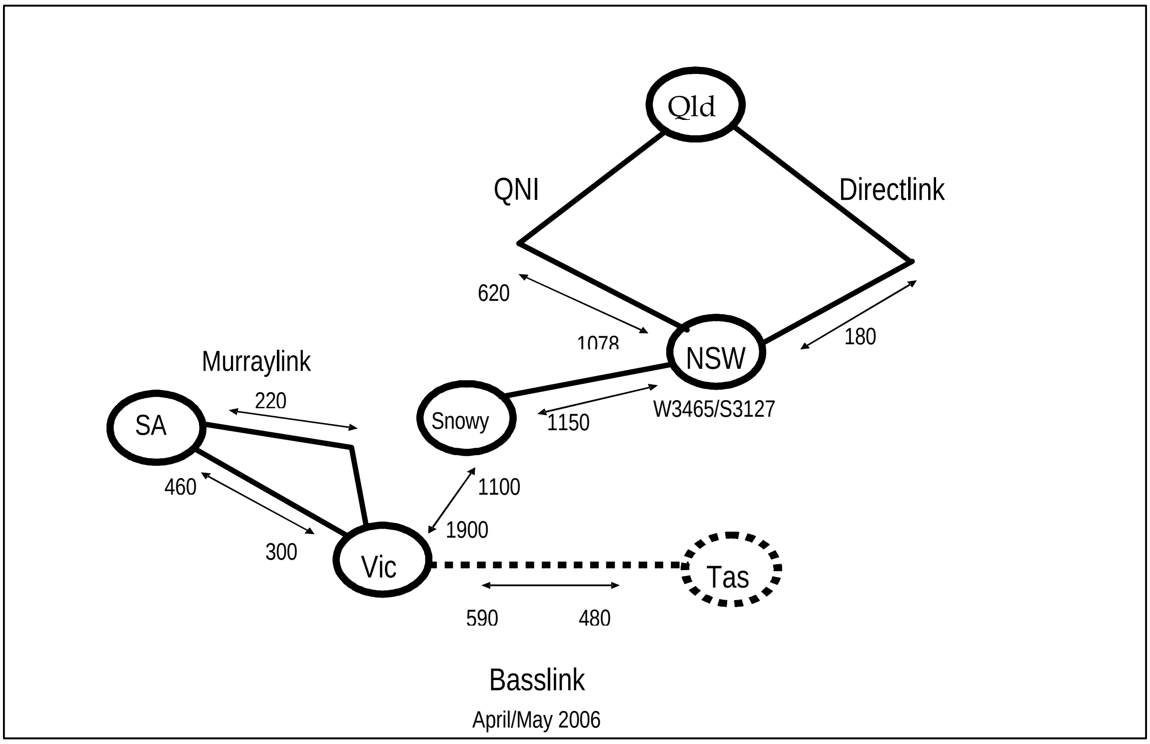
From	To	Date	Capacity	Summer
Victoria	Tasmania	Apr-06	480 MW	
Tasmania	Victoria	Apr-06	590 MW	
Victoria	South Australia		460 MW	
Victoria	South Australia	Jul-09	630 MW	
South Australia	Victoria		300 MW	
South Australia	Redcliffs		135 MW	
Redcliffs	South Australia		220 MW	
Victoria	Snowy		1100 MW	
Snowy	Victoria		1900 MW	
Snowy	NSW		3465 MW	3127 MW
NSW	Snowy		1150 MW	
NSW	South Queensland		180 MW	
South Queensland	NSW		195 MW	
NSW	Tarong (QNI)		621 MW	

From	To	Date	Capacity	Summer
Tarong	NSW (QNI)		1078 MW	

In modelling the NEM, we augment the existing interconnections according to these conceptual augmentations as required. Further upgrades to relax the Tarong limit are assumed to proceed as required to ensure that capacity in the Tarong region can reach the South East Queensland load.

MMA's pool market solution indicates when prices would support new entry under typical market conditions and these are included in the market expansion accordingly. We use cost data for potential interconnect upgrades as provided in the SOO published by NEMMCO. The model selects those expansion that are lower cost than increasing generation within constrained regions.

Figure A.3: Representation of interconnectors and their limits in Strategist



A.4.9 Transmission losses

Inter-regional losses

Inter-regional loss equations are modelled in Strategist by directly entering the Loss Factor equations published by NEMMCO except that Strategist does not allow for loss factors to vary with loads. Therefore we allow a typical area load level to set an appropriate average value for the adjusted constant term in the loss equation The losses currently applied are those published in the NEMMCO June 2005 Report V2.1 "List of Regional Boundaries and Marginal Loss Factors for the 2005/06 Financial Year".

Negative losses are avoided by shifting the quadratic loss equation so that the minimum passes through zero loss.

Intra-Regional losses

Intra-regional losses are applied as detailed in the NEMMCO June 2005 Report V2.1 "List of Regional Boundaries and Marginal Loss Factors for the 2005/06 Financial Year". The long-term trend of marginal loss factors is extrapolated for two more years and then held at that extrapolated value thereafter.

A.4.10 Hydro Modelling

Hydro plants are set up in Strategist with fixed monthly generation volumes. Strategist dispatches the available energy to take the top off the load curve within the available capacity and energy. Any run-of-river component is treated as a base load subtraction from the load profile.

These monthly energy limits provided by NEMMCO in the 2005 ANTS have been validated by comparison against historical hydro sequences that are derived from published generation data found at www.erisk.net. Erisk is a live source of combined news, prices, data and analyses for the Australian Energy Market. Where the hydro sequences appear ill-aligned to the NEMMCO energy limits, the average monthly generation levels are used in place of the NEMMCO limits to represent an estimate of the long run monthly energy limits. Table A-6 shows the monthly energies used in our Strategist model. Table A-7 shows the annual energy for the Snowy Scheme.

Table A- 6: Maximum monthly energy availability for small hydro generators modelled in Strategist (GWh)

Mth	Barron	Hume NSW	Hume VIC	Kareeya	Dartmouth	Eildon 1-2	Kiewa, McKay
Jan	13.96	4.19	18.75	23.32	24.98	19.13	10.01
Feb	20.56	3.44	15.19	22.91	26.37	14.71	10.6
Mar	22.63	0.22	14.53	23.60	11.87	15.51	5.98
Apr	15.47	0.21	6.53	20.42	3.48	7.49	4.33
May	11.28	0.00	0.62	25.02	4.71	1.37	11.44
Jun	9.40	0.00	0.09	25.80	9.58	0.32	19.4
Jul	10.07	0.94	0.01	32.05	36.78	0.88	28.89
Aug	7.93	4.47	1.09	30.18	34.77	3.3	23.06
Sep	8.51	7.86	6.97	22.61	31.76	4.98	30.8
Oct	12.02	6.71	14.61	23.34	33.33	7.4	43.71
Nov	13.38	3.47	20.25	21.30	35.99	8.98	23.03
Dec	10.52	5.91	20.66	28.05	31.14	17.6	15.93

Table A- 7: Annual Energy Limits from Snowy Hydro

	Blowering	Guthega	Murray	Upper Tumut	Lower Tumut
Annual Limit (GWh)	240	250	2210	1630	745

Based on our market information we have produced detailed information on monthly and annual maximum and minimum energy limits for the Snowy Hydro units. This information has been incorporated into the Strategist simulation as monthly energy generation.

Murray 1 releases will be progressively reduced with increasing environmental releases, particularly down the Snowy River. Snowy Hydro estimates a reduction of 540 GWh/year after the 10 year programme is completed. Consequently, by July 2012 the Murray annual energy limit has reduced to 1738 GWh per annum. However, the model allows for additional generation from Murray after its modification is complete. Additional generation is also possible from the Tumut unit if the model selects the proposed upgrade of these units.

Hydro Tasmania is represented by a single equivalent hydro power station in the Strategist model with an average annual yield of 10,133 GWh.

Table A- 8: Monthly energy inflows for Tasmanian hydro (GWh)

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Long-term	77	66	86	197	288	330	399	417	366	292	192	141	2851
Mid-term	147	120	145	325	462	495	601	595	530	435	313	230	4398
Run of river	131	110	125	206	275	311	364	364	320	280	221	177	2884
Total	355	296	356	728	1025	1136	1364	1376	1216	1007	726	548	10133

Source: ANTS 2005

The average annual yield from all 3 storages is assumed to increase once Basslink is commissioned, and so the monthly limits are pro-rated each year in line with this annual yield which appears in the above table.

A.5 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. The vertically integrated Western Power Corporation 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.5.1 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 has 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 115MW with the largest cost disproportionately allocated to the largest unit.

A.5.2 Market rules

The STEM is expected to commence operation in July 2006. Once this has been established so that it is running effectively, full retail contestability (FRC) will be considered. 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, however system management may over-ride 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. Our 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.

We have also assumed a $10,000 Value of Lost Load (VOLL) in line with the NEM, to ensure long-term supply reliability.

A.5.3 Structure of generation

The State Generator, Verve Energy, will be 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 be automatically allowed to build new plant to replace its old or inefficient plant.

Based on this discussion, 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 Western Power to bid for new entry generation as long as its overall generation capacity does not exceed 3,000 MW.

A.5.4 Demand assumptions

Three key demand parameters are used in the model:

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

We use MMRF's reference case energy sent out forecasts for the SWIS contestable market and Western Power Franchise for the period 2029/30.

We split these forecasts between regions, and added our projections of energy sent out at the Alcoa alumina refineries, 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 sent out peak demand provided by the IMO. The same load factor as is implied by the IMO forecasts are used to derive peak demand forecasts from the energy sent out forecasts provided by CoPS.

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

Using data provided by Western Power, MMA derived a SWIS load profile. This data was normalised to the peak value for the 2004/05 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.5.5 Generation assumptions – existing units

Verve Energy

Verve Energy has 11 power stations operating in the SWIS, as shown in Table B.10. The Muja stations operate as base load stations with capacity factors of 70 - 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 - 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 30MW 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 130MW 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 the following tables.

Table A- 9: 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 South West Cogeneration Venture – 120MW nameplate, 50% Western Power owned.

2 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, 2004-05, 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- 10: 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- 11. 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 1996-97 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 4 x 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- 11: 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.5.6 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-12. The same deratings are applied to all OCGTs, except for the Alcoa units. The Alcoa units are de-rated 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- 12: 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 over night, as they will no longer be needed to provide reserve.

A.5.7 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 240MW Cockburn CCGT was intended to replace the Kwinana A plants by December 2005 but has now been delayed to December 2008. In our model we assume that only these two Cockburn units will be committed, as there are restrictions on the amount of capacity that State Generation can maintain over the medium term.

We have 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 the following tables.

Table A- 13: 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
AlcoaCogen	Cogeneration	11.83	140 MW	134	Gas
Cockburn	Combined cycle	7.7	240 MW	202	Gas

Table A- 14: 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	1400 - 1600	9300	4
OCGT	3.8	3	700	1300	1
New CCGT	3.8	2	1050	3000	7
Alinta Cogen	3.8	2	900 - 950	5400	1
Cockburn 2	3.8	2	1250	3000	7

A.5.8 New renewable generation

We assume that the proposed wind farms at Walkaway and Emu Downs commence operations in 2006/07, with a capacity factor of around 35%. The Narrogin biomass plant is also assumed to continue to operate for a 20 year period. Co-firing at Muja at 5% output for one unit is also assumed to continue during the study period.

Additional renewable generation is determined as part of the renewable energy model for Australia as a whole. Additional RE generation in WA competes with options in other States in Australia to secure additional revenue from the REC market or from the emissions trading market.

A.5.9 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. Long-term levelised costs are estimated based on pre-tax costs and using a real discount rate of 9% pa.

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 the following table.

Table A- 15: 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 $35/t on a delivered basis for 19.3 GJ/t specific heat.

Nominal coal prices are assumed to increase by 75% of the inflation rate. Due to the inflator, the coal price decreases in real terms. Table B.18 shows explicitly the coal price used for each year, including transportation charges, and using a heating value of 19.3GJ/t.

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

Table A- 16: New coal price assumptions

Financial Year Ending June	New Coal Price ($/GJ)
2003	$1.81
2004	$1.80
2005	$1.79
2006	$1.77
2007	$1.76
2008	$1.75
2009	$1.74
2010	$1.72
2011	$1.71
2012	$1.70
2013	$1.69
2014	$1.67
2015	$1.66
2016	$1.65

Source: MMA assumptions

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 $2.00/GJ in 2005 dollars with price escalating at 75% of the CPI increase. The transport charge is $1.10/GJ escalating at 75% of CPI.

It is likely that in the long-term when substantial new pipeline capacity is needed that transport tariffs may increase at future regulatory reviews. This would advantage the project relative to other gas fired plants because of its efficient use of gas.

All stations owned by Goldfields Power and Southern Cross Power are modelled to use Gold gas. The estimated 2005 price of this gas is $1.90/GJ.

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.

A.6 Darwin Katherine System

A.6.1 Contestability in the NT electricity system

The operation of the contestable market is based on:

- Bilateral trading – arranging supply directly with contracted (and contestable) end-use customers.
- Supplying all of an individual contracted customers' demand under normal circumstances – partial contracting is not permitted.
- Dispatching only the quantities demanded by their contracted customers as a group from the network, unless negotiation with other generators allows them to onsell their excess generation.
- Contracting with other generators to provide and sell standby power whenever the independent generators' output is insufficient to meet their contracted supply (either because of breakdown or maintenance, or because their customers demand exceeds maximum output).

The dispatch and system control functions is undertaken by the network company of PAWA (PAWA Networks).

PAWA will act as the residual generator, absorbing over generation and making up shortfalls in generation, and will be paid a regulated fee for this service.

A.6.2 Model structure

The interconnected electricity grid in the Northern Territory is modelled as an integrated system with a transmission interconnection joining two regions: the Darwin Region and the Katherine Region. Loads include the major loads of Darwin and a number of mining site loads.

There are currently two generators in the system, PAWA and EDL who operates two power stations and sells all its electricity through PAWA.

A.6.3 Economic Dispatch

In formulating the model we assume that the bulk of electricity will be sold under bilateral contracts, with the balancing components dispatched according to economic merit order.

A.6.4 Generation

Generation in the Darwin-Katherine Interconnected System consists largely of gas-fired gas turbines supported by oil fired turbines and diesel generators. The relatively small load in the region results in generating units of relatively small size, the largest being a 37 MW gas turbine at the Channel Island power station in Darwin.

The major existing generation capacity in the DKIS is presented in Table A- 17.

Table A- 17: Installed generation

Power station	Owner	Capacity (MW)	Type	Region
Channel Island	PAWA	3 X 38.6	OCGT	Darwin
		2 X 31.6	CCGT	Darwin
		1 X 32	OCGT	Darwin
Berrimah	PAWA	2 X 15	OCGT (AVTUR)	Darwin
Katherine	EDL	3 X 6.5	OCGT	Katherine
Pine Creek	EDL	2X 10	CCGT	Katherine
		1 X 8.5	Gas diesel	Katherine
		6 X 2.7	OCGT	Katherine

Source: PAWA (2001), Annual Report 2001, Darwin; ESAA (2001), Electricity Australia 2001, Sydney.

A.6.5 Electricity Demand

We use the energy forecasts from the MMRF model and derive peak demand forecasts from the implied load factors published by the Northern Territory Utilities Commission in the recently released 2005 Power System Review.

A.7 MMA renewable energy model

MMA has a detailed database of renewable energy projects covering existing, committed and proposed projects that supports our modelling of the REC price path. 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 individual projects that are operating, committed or planned[18].

For this assignment, the data base was updated and revised. Currently, the data base comprises:

- 350 eligible renewable generators, either existing, committed or planned.

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[18] Committed plant means projects that are either under construction or have achieved financial closure. Planned projects are those being actively investigated.

- Existing RE generation accounts for 2,665 GWh per annum of eligible (above baseline) REC creation (excluding the proportion of generation sold on Green Power markets).

- Committed projects account for a further 3,820 GWh eligible REC creation, including 807 GWh attributable to solar hot water heater sales, with most of this generation coming into the market over the next two years.

- Planned projects, excluding additional solar hot water sales, amounting to 21,300 GWh of eligible renewable generation.

- Generic projects worth an additional 40,000 GWh of renewable projects. The long run marginal cost of these projects are set at a level higher than the planned projects.

Project costs have been obtained from published estimates of costs (usually capital costs) plus estimates of costs inferred from equipment suppliers, market data (for biomass fuel costs) and reports to Government. The costs are believed to be accurate to +/- 10% for existing and committed projects and +/- 20% for planned projects.

The MMA RE Model determines the future price path of RECs in the following steps:

- The costs of a range of renewable energy generation options have been determined as the levelised cost of generation using a 9.8%[19] real pre-tax weighted average cost of capital over at most a 20-year investment horizon. The model considers the time from the commencement of generation to the end of 2020 for REC revenue but only considers energy (electricity) revenue beyond 2020 earnt by the REC project if the 20 year investment horizon goes beyond 2020. The weighted average cost of capital estimate is also based on existing market rates for generation investments. Where data has been available the costs include the costs of connection to the grid, which can form a significant proportion of the capital costs of a project, particularly where no local transmission wires are available.

- The spot market price or wholesale electricity cost in each of the regions of NEM has been used as the price that a generator could obtain for the power generated in the market. Wholesale electricity prices are determined on an hourly basis for each week of the study period, using Strategist model.

- Assign regional wholesale electricity prices to all renewable projects in the data base according to location and start date. Weight wholesale electricity prices according to the generation profile of the renewable technology. For example, waste process generation would operate 24 hours per day and would therefore be represented by the average time-weighted pool price. Whereas, photovoltaics would only operate through daylight hours, achieving the prevailing market price for these hours only. Solar hot water systems although using solar energy during daylight hours, actually

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[19] Based on debt to equity ratio of 75:25, real pre-tax interest on debt of 7.3% (9.0% in nominal terms) and real pre-tax return to equity of 17%. A premium of 1% applies to biomass projects to account for fuel supply risk.

replace off-peak electricity usage so the surrogate price for this option is the off-peak price for the replaced energy.

- For each project, estimate any revenue from other sources such as fees for avoided landfill charges.
- Potential revenues from wholesale market transactions and other sources for each project are levelised for the life of the project.
- Subtract levelised revenue from corresponding renewable project levelised cost and then determine the merit order of the projects by ascending net costs (apart from those generators flagged as committed). The generation meeting the interim targets plus demand for banked credits in each year will determine which projects in the merit order will come on-line in a particular year.
- The generation output from each project is calculated from the MW and capacity factor for each project.
- The plant installed in each year is determined by the economic viability subject to the electricity price path under emissions trading.
- The resulting MW installed and generation levels are then input into wholesale electricity market model to determine the resultant pool price changes that in turn impact the electricity prices under emissions trading.
- The process may be repeated until stable outcomes result.

Assumptions on the cost of renewable generation are shown in Table A- 18. The net cost curves[20] for available renewable energy in Australia are shown in Figure A- 3. Costs are expected to fall sharply over the next decade for wind generation, with modest falls assumed for hydro-electric and biomass options. Geothermal options are also expected to be available in some states after 2010, at a long run marginal costs of between $45/MWh to $60/MWh. More details on the trends in costs for renewables are contained in Appendix B.

Table A- 18: Long Run Average Costs of Renewable Generation Options in 2006, $/MWh

Renewable Generation Type	Minimum	Maximum
Hydro-electric	78	151
Wind	73	119
Biomass	63	93

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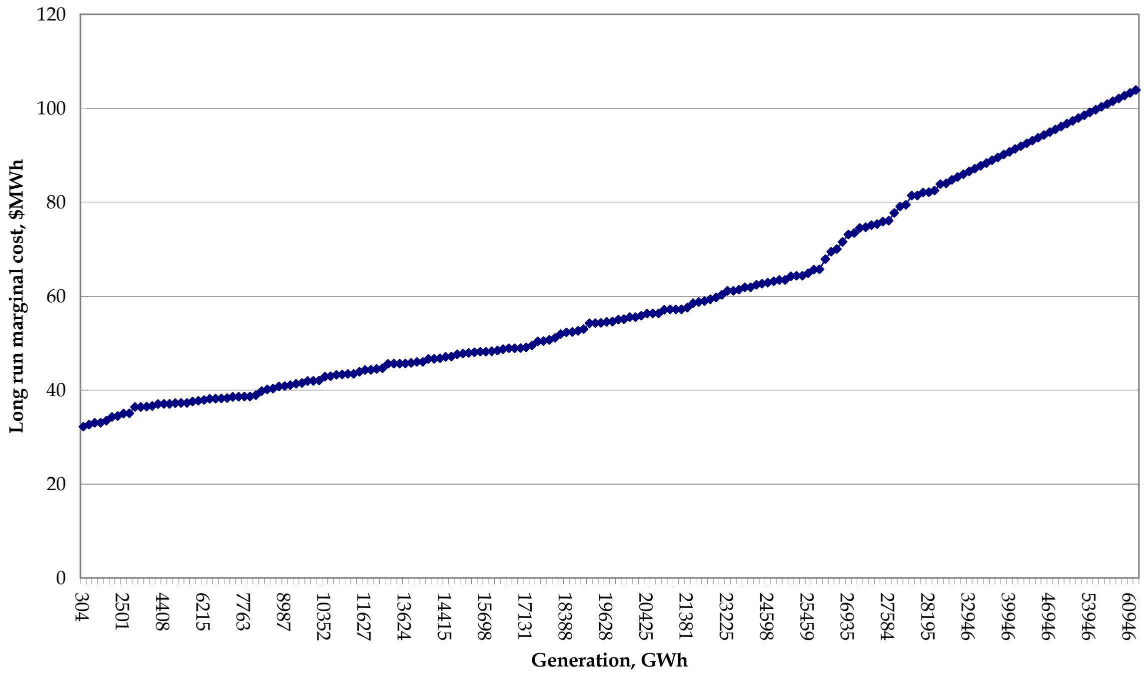
[20] Net cost is the long run average cost after deducting for revenue earnt on electricity markets.

Note: Long run average costs represent average cost (including capital, transmission, operating and fuel costs) calculated using 9.8 % pre tax cost of capital. Costs are in mid 2005 dollar terms. The costs of some renewable options are assumed to fall sharply over the period to 2020 (see Appendix B)

Figure A- 3 LRMC curves for renewable generation, mid 2005 dollar terms[21]



A.8 Biosequestration

The following assumptions regarding biosequestration uptake relate to Scenarios 1 and 2.

The model predicts the area sown to forest plantations based on returns to forest plantation and other agricultural activities. Currently, there is 1.72 million ha of land under plantation, with about 0.72 million ha devoted to hardwood plantation and 1.00 million ha devoted to softwood plantations. Based on advice obtained from industry sources, any additional area devoted to plantations is likely to come from arable land currently devoted to cropping, of which there is some 8.0 million ha.

The model predicts the amount of area sown to plantations as a function of prices for crops, prices for livestock activities and prices for forest products. Historical and projected prices for these variables were obtained from ABARE. Use of simple least squares regression analysis determined the relationship between area sown to plantations in Australia and these variables as follows:

*Area to hardwood plantation = 1422 + (-7.7 * crop price) + (8.3 * livestock price) + (13.9 * Forest product price); and*

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[21] Covers only existing, committed and proposed renewable generation projects

*Area to softwood plantation = 845 + (-5.1 * crop price) + (3.6 * livestock price) + (2.1 * Forest product price).*

Adjusted R^2 statistics ranged from 96% for the hardwood equation and 87% for the softwood equation in explaining the historical pattern of the area under hardwood and softwood plantation. All variables were significant at the 10% level of significance. Despite the reasonable diagnostic statistics for these simple models, the resulting predictions should be treated as indicative of the potential for bio-sequestration as a function of carbon price. The model does not predict permanent plantations nor the area of plantations on degraded land (such as salt affected land).

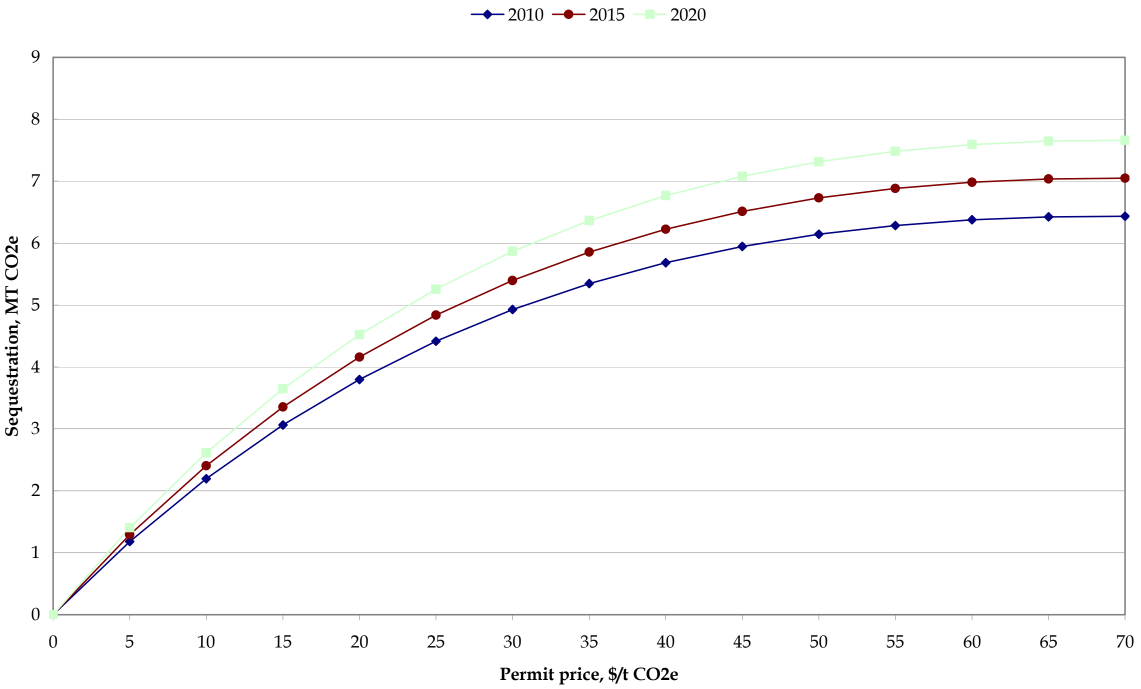
The potential for bio-sequestration is determined by adjusting the forest products price to account for the additional component for carbon and thereby calculating the area devoted to plantation as a function of this adjusted price.

Other assumptions in the analysis include:

- Crop, wood and livestock price forecasts as published in ABARE's Medium Term Outlook for Commodities. This source provided price projections out to 2010. Prices beyond 2010 were extrapolated from these projections.
- Estimates of the amount of carbon that can be sequestered per ha vary widely. We assumed the a value of 200 t CO2e/ha, which is towards the low end of the estimates and reflects the fact that plantations dedicated to sequestration are likely to be located on more marginal land and be less intensively managed.
- Only additional plantation area above 1990 levels was assumed to be able to earn credits from bio-sequestration. And only additional area above what would have occurred under business as usual (no carbon price) is assumed. This latter assumption was done as it is assumed that plantations under business as usual conditions would be harvested and potentially not replaced before 100 years (that is, the plantations under business as usual were assumed to be for eventual harvest for commercial products).
- Sequestration occurred for 20 years. Trees older than 20 years were assumed to have reached maturity and therefore would have no further sequestration.
- It was assumed that no additional revenue is obtained for salinity control benefits.

The results of the analysis are shown in Figure A- 4. The prediction indicates that about 5 million tonnes of CO_2e would be sequestered for a carbon price of $25/t CO_2e. The total level of abatement through biosequestration peaks at around 8 Mtpa. The total level of abatement at each permit price is assumed to increase slightly over time due to reduced costs of managing plantations and the improved uptake of biosequestration opportunities.

Figure A- 4: Level of bio sequestration and carbon price



APPENDIX B ABATEMENT OPTIONS AND COSTS

B.1 Energy Efficiency Options

Assumptions used to derive the energy efficiency potential are shown in the following Table. MMA's energy efficiency model selects the level and timing of uptake of energy efficiency as a function of the price of electricity. If the long term (next 10 years) electricity price exceeds the long run marginal cost of an energy efficiency option, then this option is adopted

These assumptions apply to Scenario 1 and Scenario 2. For Scenario 1a, a different set of assumptions is used based on the adoption of Government backed programs to overcome barriers to the uptake of energy efficiency. The assumptions on the level of energy efficiency for this scenario are reported in a companion document[22].

Table B 1: Assumptions on energy efficiency programs and embedded generation, Scenarios 1 and 2, 2005 values

Option	Current Potential, MW	Growth % pa	Load Factor	Emissions, t/MWh	Capital cost, $/kW	LRMC, $/MWh
NSW						
Commercial Efficiency	120	3%	47%	0.0	1000	$57
Residential Energy Eff	200	2%	42%	0.0	10000	$91
Res HW Elec to Gas	300	2%	43%	0.2	550	$43
Industrial Small Cogen	400	2%	95%	0.4	1500	$60
Victoria						
Commercial Efficiency	25	3%	76%	0.0	1000	$57
Residential Energy Eff	40	2%	68%	0.0	10000	$91
Residential Displacement	75	2%	39%	0.3	550	$43
Industrial Small Cogen	100	2%	95%	0.3	1500	$60
South Australia						
Commercial Efficiency	5	3%	70%	0.0	1000	$45
Residential Energy Eff	10	2%	84%	0.0	10000	$91
Residential Displacement	15	2%	34%	0.3	550	$43
Industrial Small Cogen	20	2%	95%	0.3	1500	$60
Queensland						
Commercial Efficiency	20	3 %	75%	0.0	1000	$55
Residential Energy Eff	30	2%	55%	0.0	10000	$91
Residential Displacement	60	2%	35%	0.3	550	$43
Industrial Small Cogen	80	2%	95%	0.3	1500	$60

Source: MMA analysis based on data provided by NSW SEDA, Sustainability Victoria and NFEE. The LRMC data represent costs at the busbar. Costs are reduced in the model for some options if there are transmission savings to be had with the option.

These energy efficiency options were modelled in the simulation model as load modifiers, reducing the load shape in accordance with the assumed impact of the option. Thus, an

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[22] See Insight Economics (2006), The Economic Impacts of a National Emission Trading Scheme, report to the National Emission Trading Taskforce, June

energy efficiency program was assumed to reduce demand either by a constant amount in all periods, or by concentrating load reductions during peak periods only.

In scenarios 1 and 2, it was also assumed that there is a delay in the uptake of energy efficiency before its market potential under an emissions trading scheme is reached. The uptake rates are as follows:

Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
10%	20%	33%	50%	67%	80%	100%

It was also assumed that the potential energy efficiency implemented was one third to one half of the total potential calculated. The levelised costs shown in the above tables are based on an assumed economic life of the energy efficiency program of 10 years. Reducing the total potential by one third to one-half reduces the implied payback period to 3 to 4 years.

B.2 Cost of new generation options

B.2.1 Renewables

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

MMA's renewable 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 largely based on the assumption that cost reduction opportunities for most technologies are likely to reduce to a lower value than pre-2026 levels, due to the assumption that 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[23].

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

Table B 2: 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%
Hydro (small scale)	0.7%	0.6%	0.6%
Wave	5.0%	4.0%	4.0%

Hydroelectricity cost estimates are based on the values likely for small to medium sized developments (less than around 50 MW) in MMA's database. This is due to the fact that the vast bulk of Australia's hydro (large scale) potential has already been harnessed and any new projects are likely to involve the addition of capacity or refurbishment of existing large-scale developments, or the development of new mini-hydro plants.

As pointed out by the IEA, the hydropower industry is well established in many parts of the world and further opportunities for cost reductions are likely to be quite small compared with other renewable technologies. The exception is developing countries that display considerable potential for greater development. In particular, the potential for capital cost reductions from improved technology is likely to be limited, due to the advanced nature of existing turbine design.

Estimates by the IEA indicated capital costs in 2003 dollar terms of around USD $1,000/kW (approximately AUD $1,333/kW at an exchange rate of US 75 cents to the Australia dollar) to USD $5,000/kW (AUD $6,666/kW). MMA's 2005 estimate of around $1,760/kW is therefore at the low end of IEA's cost estimates. Further opportunities for capital cost reductions in Australia are therefore based on the IEA's low case estimate (around 0.6% per annum) and are not expected to change noticeably over the forecast period.

Table B 3: Parameter values for hydroelectricity

Parameter	Units	Low cost	Medium cost	High cost	Change from 2005 to 2050
Size	MW	43.0	43.0	43.0	Unchanged
Life	Years	25	25	25	Unchanged
Real pretax WACC	%	9.0%	9.0%	9.0%	Unchanged
Capacity factor		0.30	0.30	0.30	Increase from 0.30 in 2005 to 0.35 in 2020 and remains constant
Capital cost 2005	$/kW	1,496	1,760	2,024	Unchanged
Interest during construction	%	7.0%	7.0%	7.0%	Unchanged
Capital cost reduction	%	0.6%	0.6%	0.6%	Reducing over time
Fuel costs	$/MWh	0.0	0.0	0.0	Unchanged
O&M costs	$/MWh	0.0	0.0	0.0	Unchanged
Ancillary service costs	$/MWh	0.0	0.0	0.0	Unchanged
Transmission costs	$/kW	100	100	100	Unchanged

The maximum additional potential mini-hydro plant is assumed to be around 100 MW, mainly in the eastern seaboard of Australia.

Generation costs for Australian wind farms in 2005 are based on MMA's database of RE projects in 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)[24]. From 2011 to 2025, the rate of decline in capital costs is assumed to decrease to around 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 placing downward pressure on achievable capacity factors[25]. It has therefore been assumed that average capacity factors will increase linearly by 2 percentage points by 2020. However,

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

[25] AusWEA, 2004, *Cost Covergence of Wind Power and Conventional Generation in Australia*, Melbourne.

from 2021 onwards, siting issues are expected to completely eliminate any further potential for increases in average capacity factors.

Table B 4: 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% percentage points from 2005 to 2020 and does not increase further after this date
Capital cost 2005	$/kW	1350	1700	2050	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

For biomass projects, 2005 cost estimates are primarily based on a recent report published by the Rural Industries Research and Development Corporation[26].

WACC is assumed to be slightly higher than some of the other renewables (1 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 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

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[26] 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.

more[26]). 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 technologies such as wind.

Table B 5: Parameter values for bioenergy

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

For geothermal energy, the rate of decrease in capital costs from 2005 to 2010 of 4.0% p.a. is assumed to be slightly higher than the average of IEA's estimate of around 3.5% p.a. This rate of reduction is higher than all other renewable technologies (except solar PV). This seems reasonable, since geothermal technology is in its infancy in Australia and significant cost reduction opportunities are expected to occur as the installed capacity and level of experience in Australia increases.

High rates of potential cost reduction are expected to continue from 2011 to 2025 (around 3.5% per annum). From 2026, onwards cost reduction opportunities are expected to reduce, but still be quite high compared to the other renewables. A value of 2.0% per annum has been assumed.

Despite a higher rate of capital cost reduction than wind, the overall rate of reduction in levelised costs does not show a marked difference compared to wind because capital costs contribute less to overall costs than in the case of wind farms. This is primarily due to the assumption that transmission costs are higher for geothermal plant.

Geodynamics states that operating costs for geothermal plant are in the order of $10-20 /MWh (depending on scale) and relate mainly to the costs of pumping water through an underground heat exchanger and the maintenance of an above ground geothermal power plant. In MMA's modeling, $15/MWh is assumed. The capacity factor is assumed to increase from 80% in 2005, to 85% in 2020.

Interest during construction is assumed to be slightly higher than some of the other renewable technologies (1 percentage points higher), since it can take several years to drill wells. The degree of uncertainty associated with the geothermal cost estimates presented here is likely to be comparatively high, since a fully commercial HDR plant has yet to be built in Australia (although construction and drilling work has commenced on demonstration plants).

Information on the Geodynamics website indicates that by scaling up geothermal plants to 300 MW capacity, it may be possible to achieve total generation costs as low as $40/MWh[27]. No timeframe is indicated for the achievement of these low costs, however MMA's cost estimates indicate that $40/MWh may indeed be achievable, but not until after 2018.

Table B 6: Parameter values for geothermal energy

Parameter	Units	Low cost	Medium cost	High cost	Change from 2005 to 2050
Size	MW	50.0	50.0	50.0	Unchanged
Life	Years	17	17	17	Unchanged
Real pretax WACC	%	9.0%	9.0%	9.0%	Unchanged
Capacity factor		0.80	0.80	0.80	Increase from 0.80 in 2005 to 0.85 in 2020 and remains constant
Capital cost 2005	$/kW	2080	2600	3120	Unchanged
Interest during construction	%	10.0%	10.0%	10.0%	Unchanged
Capital cost reduction	%	4.0%	4.0%	4.0%	Reducing over time
Fuel costs	$/MWh	0.0	0.0	0.0	Unchanged
O&M costs	$/MWh	10.0	15.0	20.0	Unchanged
Ancillary service costs	$/MWh	0.0	0.0	0.0	Unchanged
Transmission costs	$/kW	250	250	250	Unchanged

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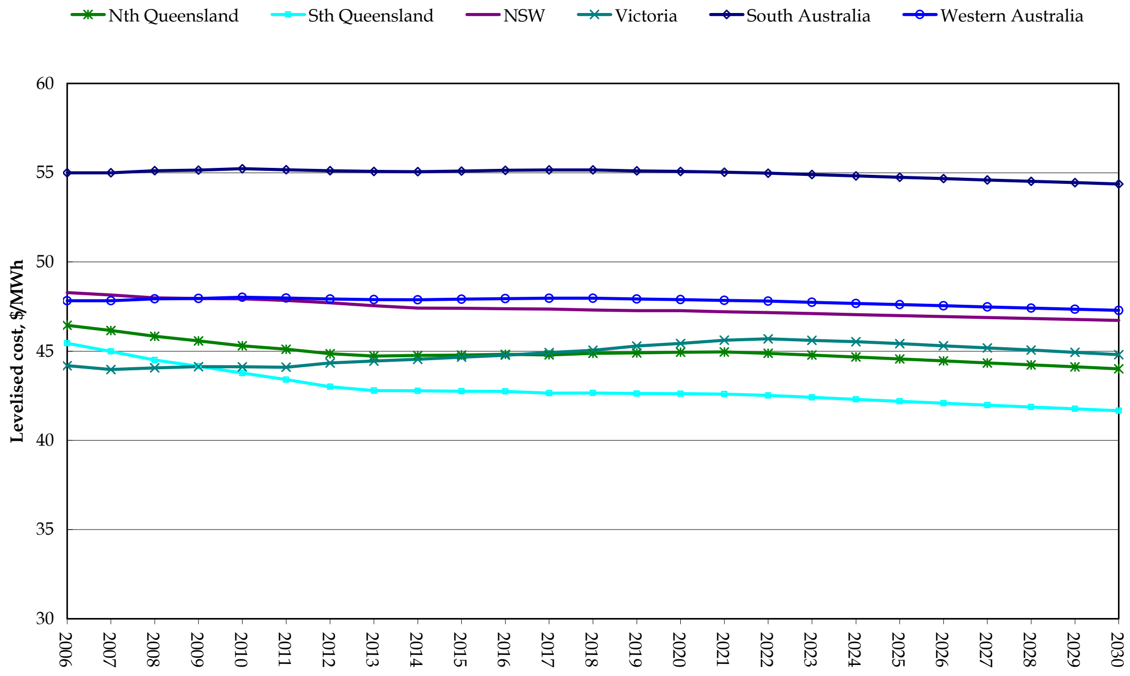
[27] Geodynamics website. Source: http://www.geodynamics.com.au/IRM/content/02_hotdryrock/02.1.5.html, Last accessed, 18 October 2005.

B.3 Natural gas & coal seam methane

Cost curves for base load gas-fired generation is shown in Figure B- 1. The cost estimates are based on the assumption of a moderate decline in real capital costs (of about 1% per annum from 2010 onwards) and modest improvement in thermal efficiencies to a maximum thermal efficiency of 65% by 2025 (5.6GJ/MWh) for the larger sized machines. Note the costs are the mean LRMC of gas fired generation for each State. The costs may be lower or higher than shown depending on location of the gas plant within the State (due to differences in gas transmission costs).

Figure B- 1: Cost curves for CCGT technology, 100% capacity factor



B.4 Clean coal and geosequestration

There are currently three main capture technologies: pre-combustion capture, post-combustion capture and oxy fuel firing, and the use of membranes.

B.4.1 Pre-combustion capture

Pre-combustion capture is normally achieved through integrated gasification combined cycle (IGCC) technology. The coal gasification portion of IGCC plants combine coal with oxygen to produce a gaseous fuel, which is passed through a shift converter to give hydrogen and CO_2. The CO_2 can be separated and the hydrogen then combusted in a gas turbine to produce electricity.

Pre-and post-combustion systems can capture 85 to 95% of the CO_2 emissions, resulting in ultra-low emissions. The higher pressure and concentrations of the CO_2 in pre-combustion systems make separation easier than post-combustion systems; however, it also involves more radical and complex changes in power plant designs and the initial fuel conversion steps.

Similar technologies are used in large-scale hydrogen production and although IGCC plants are relatively common, only a few incorporate CO_2 capture.

We only assume pre-combustion capture technologies associated with clean coal generation technologies in this study due to the availability of data on this technology. We recognise other capture technologies may be developed in the time frame of this study and that these technologies may be of lower cost than the pre-combustion technologies.

B.4.2 Carbon capture and geological storage costs

The capture component has been noted to comprise 70 to 90% of the total costs of carbon capture and storage, but is forecasted to reduce by 20 to 30% over the next decade as technologies improve.

The following range of costs reflects differences in designs of systems and assumptions used in different studies. Since carbon capture and storage systems have not been built at a full commercial scale, these costs cannot be stated with a high degree of accuracy.

Table B 7: CO_2 capture costs for new plants based on current technology

Type of System	Range of capture costs			
	$ / MWh		Percentage increase in LRMC	
	Min	Max	Min	Max
Integrated Gasification Combined Cycle	12	29	20	55
Super Critical Pulverized Fuel	24	45	40	85
Natural Gasification Combined Cycle	16	32	35	75

Source: IPCC, 2005. Special Report on Carbon Dioxide Capture and Storage, Technical Summary

Transport costs strongly depend on the distance, quantity transported as well as other factors such as onshore or offshore pipelines. Costs for a 250 kilometre pipeline, or shipping of similar distance for 5-40MtCO_2/yr, can fall in the range of $1.3 to 10.7/t$CO_2$[28].

Geological storage costs are more accurate, because similar technologies are widely used in the oil and gas industries. They are however, still dependant on many factors such as geological formation and reservoir depth. Estimates of the cost for storage in saline formations and oil and gas fields are typically between $0.7-$10.7/tCO_2 injected. Monitoring costs and liabilities due to possible leakages will also add to these costs.

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[28] IPCC, 2005, *Special Report on Carbon Dioxide Capture and Storage*, Technical Summary.

Table B 8: Range of total costs based on current technology for new power plants, 2010

Power plant performance and cost Parameters	**Integrated gasification combined cycle**		**Super critical pulverized coal**	
	Min	Max	Min	Max
Reference plant without CCS				
Cost of electricity ($/MWh)	54.7	81.3	35.0	40.0
Power plant with capture and geological storage*				
Cost of electricity ($/MWh)	68.0	121.3	60.0	105.0
Cost of CCS ($/MWh)	13.3	40.0	25.0	65.0
Mitigation cost ($/t CO_2 avoided)	18.7	70.7	20.0	52.0

Source: IPCC, 2005, Special Report on Carbon Dioxide Capture and Storage, Technical Summary; MMA analysis
* Storage combined with enhanced oil and gas recovery can lower these costs which could yield benefits of $AUD 13.3-21.3 /t$CO_2$[29].

Goals of various projects aim to reduce the cost of carbon sequestration to $13/tonne of carbon dioxide stored by 2015[30]. Current capture costs are significantly larger than that amount, but will undoubtedly decrease as the technology improves and scales increase.

The forecast cost of CCS is provided in the following chart, representing the expected additional costs of IGCC generation if the costs associated with carbon capture and storage are included. It is assumed that CCS technology will result in around 80% of total CO_2 emissions being captured. Note that cost curve shown is a single representative value for Australia in each year, however, costs will vary by state. Some states such as Victoria and Queensland will have significantly lower cost than shown due to the assumed close proximity of storage basins.

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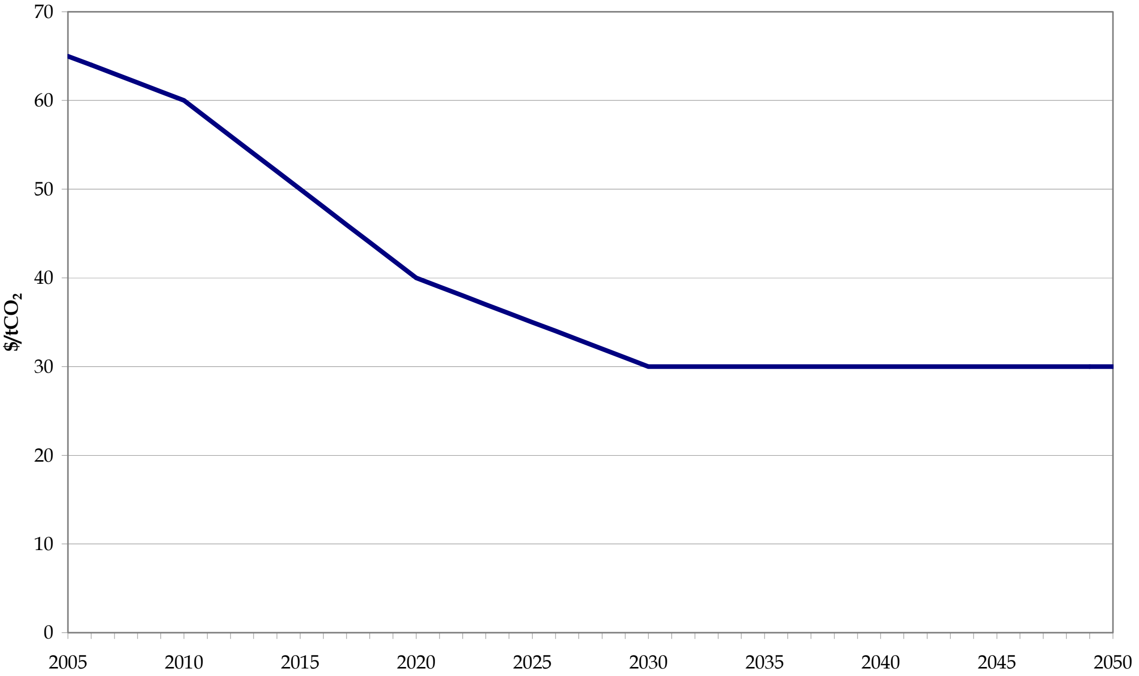
[29] IPCC, 2005, *Special Report on Carbon Dioxide Capture and Storage*, Technical Summary.

[30] Feron P. 2005, *Progress in Post-Combustion CO2 capture* – Presentation.

Figure B- 2: Forecast cost of CCS in Australia, average over all States of Australia



Capture costs are assumed to fall significantly between 2010 and 2030 as the technology is improved and production scales up. After 2030, the cost of capture is assumed to remain fairly steady as the technology is projected to mature and as lower cost capacity becomes scarce.

Capture of carbon dioxide also involves a penalty in terms of energy required to undertake the process. The additional energy required is captured in the cost estimations through the higher heat rates (that is, lower thermal efficiency). The assumption used is that there is a 20% penalty in heat rate involved in capture of CO_2.

Costs of storage are very site specific and they are expected to fall only at a modest rate as storage involves relatively mature technologies. There are two conflicting trends in storage costs. On the one hand, higher levels of storage requirements will lead to economies of scale in storage, namely large diameter pipes and so on. On the other hand, as the storage requirement increases, the gas will need to be piped to more distant basins, increasing the average cost of storage. We have assumed a modest decrease in storage costs.

The extent of accessible storage volume is highly uncertain at this time. The GEODISC program has estimated theoretical potential of 1,600 years of storage at current emissions rates. However, the program, in noting that the best storage sites are remote from the major point sources, estimates a practical capacity at around 120 Mtpa based on current information.

CCS costs are added to the non-CCS costs to construct the cost curves for conventional fuels including geosequestration.

B.4.3 Integrated gasification combined cycle (IGCC)

The coal is gasified by reacting a coal/water slurry with oxygen at high temperature and pressure in a gasifier. The resultant product is called 'syngas' and is a mixture of carbon monoxide and hydrogen, which can be used as a feedstock in chemical manufacture and as a combustion fuel. Alternatively, the syngas can be further processed via a water shift reaction to convert the CO to CO_2 in more concentrated form which can be more easily captured, and hydrogen which could become the final fuel for the combined cycle gas turbine. The CO_2 can be used in other processes (advanced oil recovery, or prospectively, enhanced coal bed methane (ECBM)) or could be injected into deep underground geological formations for long-term storage. Hydrogen has a heat value of 121 MJ/kg, which is almost five times that of coal, so it is a very energy-intense fuel.

Approximately 20% of the electricity produced through IGCC is used to separate oxygen and nitrogen in air. The separated oxygen is used as a feedstock to the gasifier. Because the gasifier is fed with oxygen rather than air, the highly concentrated CO_2 can be readily captured at about half the cost of post-combustion capture from conventional plants (14% concentration of CO_2).

The current efficiency of an IGCC is approximately 36.5% (higher heating value, HHV). The US Department of Energy (DOE) estimates that for IGCC power plants, the potential long-term expected efficiency is approximately 45 to 50% (HHV) or net cycle efficiency of 40 to 45%, due to a 5% loss from gas cooling to allow for cleaning.

There are currently 160 commercial IGCC plants world-wide, with 75% for chemicals and fuels applications (petroleum coke and heavy residues). However, it is forecast that 70% of the planned IGCC capacity to be added over the next four years will be for power production[31].

B.4.4 Advanced steam cycles for coal-fired power plants – SCPF, USCPF, advanced SCPF

Coal fired power plants have undergone many changes since their conception to reduce emissions and improve efficiency. Some of these include:

- Coal washing to reduce fly ash and sulphur dioxide emissions.
- Electrostatic precipitators and fabric filters which remove 99% of the fly ash from the flue gases.
- Flue gas desulphurisation.
- Low-NO_x burners to reduce nitrogen oxide emissions by up to 40%.
- Ultra-clean coal from new processing technologies which reduce ash and sulphur emissions.

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[31] Victor de Biasi 2003, "Future generation IGCC to convert coal into hydrogen and electric power", In *Gas Turbine World,* September-October Issue, Southport, United States.

- Gasification, including underground gasification in situ.
- Improved efficiency due to design or construction materials. The supercritical steam turbine offers improved cycle efficiency due to the increased temperature and pressure inside the steam tubes. The current achieved efficiency of a supercritical plant is up to 42% (HHV). The materials used inside a supercritical plant are iron based alloys, which it is estimated will allow the efficiency to reach up to 50% (lower heating value, LHV basis) by 2015. However due to maximum operating temperatures and pressures of iron based alloys, there is currently a lot of research into nickel based super alloys which may enable efficiencies of up to 56% (HHV) at 700^{o}C by 2020. The use of such alloys will result in higher capital costs, offset by higher efficiencies and lower operating costs.

The standard steam operating parameters for current and potential technologies are as follows:

- Supercritical 300 bar/600 degree Celsius.
- Ultra - supercritical 320-330 bar/610 degree Celsius.
- Advanced supercritical 375 bar/700 degree Celsius (Nickel “Super” alloy).

Although the range of advanced coal generation technologies, both current and proposed, offer higher electrical efficiencies than for pulverised fired boilers used in most Australian plants, these technologies do little to improve emissions, which are considerably higher when compared to single shaft CCGTs. If efficiency of black coal generators can be increased from 40 to 50%, CO_2 emissions could be reduced from 0.88 t/MWh to around 0.68 t/MWh.