Report to

NSW Department of Environment, Climate Change and Water

Estimating Greenhouse Gas Emissions Abatement from Wind Farms in NSW

July 2010

MMA McLennan Magasanik Associates

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ABBREVIATIONS

CCGT	Combined cycle gas turbine
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
DSM	Demand side management
LUACs	Large User Abatement Certificates
MMA	McLennan Magasanik Associates
MRET	Mandatory Renewable Energy Target
MSW	Municipal Solid Waste
MW	Mega Watts
NEM	National Electricity Market
AEMO	Australian Energy Market Operator
NGAC	NSW Greenhouse Abatement Certificate, which can be earned under the NSW Greenhouse Gas Abatement Scheme
NGeS	Next Generation Energy Solutions
NIEIR	National Institute of Economic and Industry Research
ORER	Office of the Renewable Energy Regulator
POE	Probability of Exceedance
PV	Photovoltaic generation
QGEC	Queensland Gas Electricity Certificate
QNI	Queensland NSW interconnect
RECs	Renewable Energy Certificates
SHW	Solar hot water heaters
ESOO 2009	Electricity Statement of Opportunities 2009, a document published by AEMO to provide information on the electricity demand and supply situation in the NEM

EXECUTIVE SUMMARY

This report has been prepared for the NSW Department of Environment, Climate Change and Water to report on electricity market modelling that has been carried out to determine the emissions abatement impact of wind farms located in New South Wales.

The greenhouse gas abatement from wind energy is specific to each electricity system, primarily because the generation that is displaced by the output of a wind farm is location-specific. In NSW, wind farms would almost exclusively displace fossil-fuel generation, either from NSW coal-fired and gas-fired generators, or from coal-fired generators in Queensland and Victoria.

The present study consists of four scenarios, each with a different level of wind penetration in NSW from 2010 to 2020:

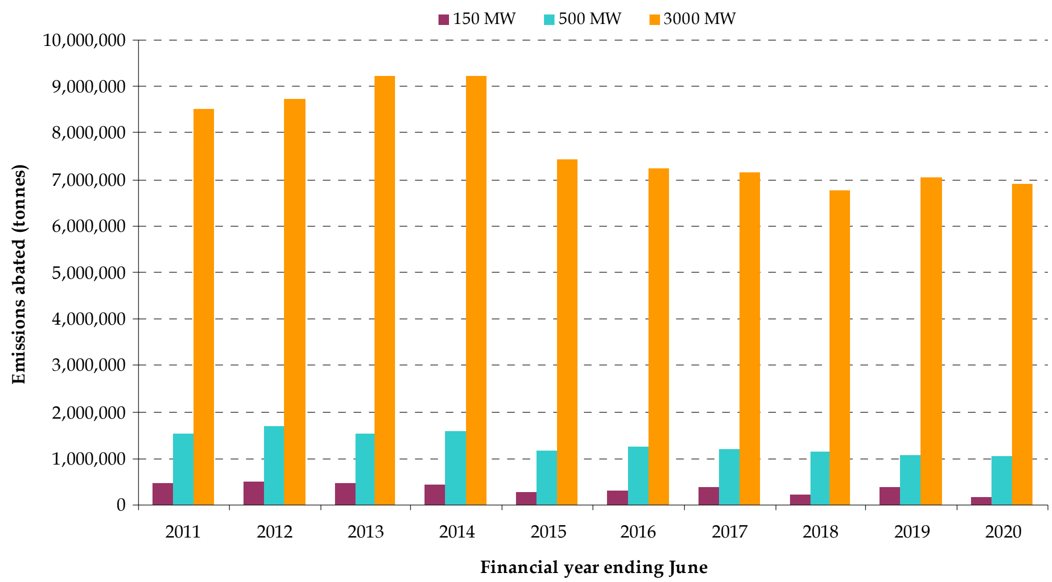
- Scenario one: the baseline scenario in which no new wind capacity enters NSW.
- Scenario two: a 150 MW wind farm (an average large wind farm).
- Scenario three: 500 MW (a very large wind farm).
- Scenario four: 3,000 MW of wind capacity (the upper range of wind capacity that would be expected to penetrate the NSW market under the expanded RET scheme).

Each of these cases were set to run using the PLEXOS electricity market simulation software package, and the modelling horizon was set from July 2010 until June 2020.

As Executive Figure 1 illustrates, the greenhouse gas emissions abated by NSW wind farms varies annually over the modelling horizon:

- Scenario two (150MW wind farm): from 150 kt CO_2e to 450 kt CO_2e per annum.
- Scenario three (500MW wind farm): from 900 kt CO_2e to 1,600 kt CO_2e per annum.
- Scenario four (3000MW wind capacity): from 6,900 kt CO_2e to 9,000 kt CO_2e per annum.

Executive Figure 1 Emissions abated in NSW for 150 MW, 500 MW and 3000 MW cases



There is a clear step down in the abatement level from 2015 onwards, which coincides with the commencement of the CPRS assumed for this study. This occurs because pre-CPRS there is relatively little supply from NSW gas-fired generation, and most of the wind capacity displaces black coal plant, which has higher emissions intensity relative to gas plant. Post-CPRS gas-fired generation becomes more competitive against black coal and generates in greater volume. As a consequence of this, wind capacity displaces a greater proportion of gas-fired generation (although the proportion is still much lower than that of the coal-fired generation that is displaced) and therefore the average abatement intensity of the wind capacity reduces, resulting in less greenhouse gas emissions abatement for the same volume of wind capacity.[1]

Another finding of the modelling was that the average emissions intensity of electricity generation in NSW decreases over time. This is driven by (i) increased penetration of renewable generation sources due to the expanded RET scheme; (ii) increased dispatch of lower emissions gas plants, which is driven by the introduction of a carbon price under the CPRS; and (iii) the commissioning of new low emission gas turbine power stations over the modelling time frame.

Finally, there is some variation in greenhouse abatement depending on the location of wind farms across the six wind precincts. The level of greenhouse abatement is quite similar for five of the six precincts, but it was found that the most greenhouse abatement occurs for wind farms located in the Cooma-Monaro region, which is mainly due to

1 Consequently, if a carbon price is not implementedthrough the CPRS (or a alternative emissions trading scheme or carbon tax), the greenhouse gas abatement from NSW wind farms would be higher than projected in this study.

favourable marginal loss factors[2] in the region and the good quality wind resource. The abatement for wind farms located in the South Coast region is notably lower, mainly because the quality of available wind resources are not as good as those of the other regions.

2 Marginal loss factors represent the losses incurred during transmission of electricity from generators to load centres

1 INTRODUCTION

This report is prepared for the NSW Department of Environment, Climate Change and Water to outline findings of electricity market modelling that has been carried out to determine the greenhouse gas emissions abatement impact of wind farms located in New South Wales.

The report outlines the market assumptions and methodology used to estimate the impact of NSW-based wind farms in the National Electricity Market (NEM), and also reports the results of the modelling. The modelling was developed for a medium economic growth scenario, with a 50% probability of exceedance (POE) as presented in the 2009 AEMO Electricity Statement of Opportunities (ESOO).

The discussion focuses on the assumptions leading to spot market outcomes including details on:

- New generators by regions.
- Inter-connector capacities and timing.
- Treatment of the operation and development of greenhouse gas abatement schemes.
- The carbon pollution reduction scheme.
- Fuel costs.
- New entry timing and costs.

The wind farm impacts are developed for the period from 1 July 2010 to 30 June 2020.

2 EXPECTED EVOLUTION OF RENEWABLE ENERGY TARGET

2.1 Design of the Expanded Renewable Energy Target (RET)

The Australian Government intends for the equivalent of at least 20% or 60,000 GWh of Australia's electricity supply to be generated from renewable sources by 2020. To enable this it has been legislated that the existing Mandatory Renewable Energy Target (MRET) will be increased to 45,000 GWh to ensure that, together with the approximately 15,000 GWh of existing renewable capacity, this target will be met. Existing renewable generators are eligible to create Renewable Energy Certificates (RECs) provided they can demonstrate renewable electricity production above a specified baseline. The previous national MRET and existing state based targets have been merged into a single national scheme where only renewable energy counts toward the target. The target will remain constant from 2020 to 2030 as emission trading matures and prices become sufficient to ensure a RET is no longer required. Projects which have been approved under existing state based schemes will remain eligible under the expanded RET and will be able to earn certificates until 2030. Additional provision has been made for existing power production from waste mine gas to earn certificates as the NSW Greenhouse Gas Abatement Scheme will no longer provide support when the CPRS is commenced. This provision has not affected the impact on renewable energy resources.

The market for renewable energy is guaranteed to suppliers via legislative obligation for retailers and large users to purchase an increasing proportion of their energy from renewable sources. Liable parties demonstrate their compliance by acquiring and surrendering RECs or pay a shortfall charge of $65/MWh.

2.1.1 Banking of RECs

The new scheme includes unlimited banking; i.e. RECs remain valid until the end of the scheme or until they are surrendered. This banking period has strong implications for providing sufficient capacity early enough to meet the target, and can also affect the liquidity of the REC market as well as the costs of the scheme and the technology mix put in place. Options that are more expensive now but are expected to be cheaper later may be put in earlier as a result of banking. Access to these more expensive options helps to ensure there is sufficient capacity to meet the target and that the long-term costs and benefits are taken into consideration when new entrants decide to invest in renewable generation. Renewable generation in early years can therefore be greater than the target during these years and possibly less than the target in later years. However, this accelerated development which was observed under the previous MRET is now expected to be less intense because the CPRS will result in increasing energy prices over time and therefore declining REC prices. This undermines the value of surplus RECs.

2.1.2 Project eligibility periods

The project eligibility period is the number of years during which a renewable based power station that is accredited under a scheme is entitled to create RECs. RECs created during this period can be sold to supplement revenue from the sale of the electricity generated. The RET scheme allows all accredited power stations to create RECs for the duration of the scheme. The previous expectation that existing MRET generators (i.e. pre-December 2007 generators) may be excluded beyond 2020 to avoid windfall gains has not eventuated since existing generators will be eligible to participate until the end of the scheme. Therefore, there may be an oversupply of RECs to meet the non-increasing target post 2020, resulting in softer prices. Eventually there will be a price fall as carbon price increases the price of energy.

2.1.3 Duration of the expanded RET scheme

The purpose of the expanded RET scheme is effectively to provide early incentives for renewable generation during the early years of a CPRS. The expanded target will have a significant upward impact on the REC price relative to the original scheme, and this will flow into the revenue stream available to a new entrant in the renewable supply sector. Such an incentive is essential for renewable generation to compete with thermal sources of generation, particularly when investment in renewable generation typically requires at least 10 years of a secure revenue stream.

It is expected in later years of the CPRS (i.e. between 2020 and 2030), that renewable generation will become competitive and viable without the need for an expanded RET scheme. During this period electricity prices should rise to a sufficient level to support renewable generation without the price support provided by the expanded RET scheme. When renewable energy can compete with carbon priced thermal energy the value of RECs would drop to zero and the scheme would become redundant. The timing of this end stage depends on the evolution of carbon price and the future cost of renewable energy technologies compared to thermal technologies.

3 MEASURING EMISISONS ABATEMENT FROM WIND FARMS

There are a number of issues that need to be considered in attempting to estimate the actual level of emissions abated from wind farms. These can be summarised under three points:

- What is the generation mix that is displaced by wind generation?
- What is the level of emissions abated by wind farms over their life cycle?
- To what extent does the variability of wind reduce its emissions abatement benefit?

All three questions are specific to the characteristics of the electricity system that is the subject of the study, and must therefore be considered in that specific context.

3.1 Generation mix displaced by wind

In the NEM, generation from wind output is generally bid into the pool at zero dollars. Thus it will be located deep in the bid stack (usually just after the must-run generation segments, which are bid in at negative prices) and will usually be fully dispatched. The net effect of this is that wind reduces demand for electricity from other sources, which are typically bid in at or above their marginal cost of generation. In other words, wind displaces generation from the top of the bid stack (the marginal generator), and if this generation source would have used fossil fuel to produce electricity, then the use of wind would have reduced emissions from the electricity supply sector.

In the NSW context, the primary fuel source for electricity generation is black coal, although gas is now playing an ever-increasing role, whereas hydro generation still plays an important peaking role. The other major sources of electricity generation are imports from Queensland and Victoria, both of which possess cheaper coal-fired generation resources. The three major government-owned NSW coal-fired generators tend to control the wholesale price of electricity in NSW, which means that black coal is often the marginal generator in NSW. We would therefore initially expect to see wind generation in NSW displacing coal, and to a lesser extent, gas and electricity imports.

The proportions of fuel sources being displaced would most probably change post-CPRS, since the introduction of a carbon price changes the merit order of dispatch.

It is unlikely that wind would ever displace hydro generation for two key reasons. Firstly, hydro generation is a storable, energy-constrained resource. Thus, if it were hypothetically being displaced by wind at a particular point in time, it could be stored in a dam and released at another time when the wind was not blowing. This would not substantially[3] alter the total amount of energy generated from the stored water. Secondly,

3 There may a very minor amount of hydro energy lost in storage due to evaporation.

hydro is often a price-taker in the market, meaning that it is often bid into the pool at zero dollars, just as wind is. The upshot of these two points is that wind in NSW would be almost exclusively displacing fossil fuel, either from NSW coal-fired and gas-fired generators, or from coal-fired generators in Queensland and Victoria.

3.2 Level of emissions abated by wind

There are two factors that need to be considered in answering this question. Firstly, how much emissions are abated from the electricity output of the wind farm due to the displacement of fossil fuel generation. Secondly, how many emissions were produced in the manufacture, construction and operation of the wind farm itself.

As discussed in the previous section, in the NSW context, almost all wind generation would displace fossil fuel generation, although some of this generation may be situated in Victoria or Queensland. A previous study by MMA for Sustainability Victoria investigated the level of emission abatement by wind in Victoria[4], and found that the abatement intensity from wind generation depended on the level of installed wind capacity, and also tended to decrease over time. The abatement intensity projected from 2007 to 2015 averaged to 0.93 t CO_2e/MWh for 100 MW of installed wind capacity and 1.08 t CO_2e/MWh for 1000 MW of installed wind capacity. These abatement intensities are well below the average emission intensity of generation in Victoria, which was at the time roughly 1.3 t CO_2e/MWh. This implies that wind generation displaced a mix of both gas-fired and coal-fired generation.

The emissions resulting from the manufacture, construction and operation of wind farms are actually quite low relative to those associated with the manufacture, construction and operation of large fossil fuel plants. The evidence suggests for a wind farm of average output that it takes about 14 kg CO_2e/MWh to manufacture, build and operate a 50 MW wind farm[5,6]. This represents less than two percent of the typical emissions reduction that such a wind farm would achieve from displacing fossil fuel generation.

3.3 Impact of wind's variability on emissions abatement

The minute-to-minute variability in wind farm output, which arises from varying wind speed and direction, and is therefore not controllable, is managed in the NEM via frequency control ancillary services (FCAS). There is no evidence of a significant increase in the use of FCAS to deal with wind variability, which is not surprising given the low level of wind farm penetration currently in the NEM. However, it is likely that the need for FCAS will increase at some point as more wind is installed in the NEM[7]. This will

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4 MMA, *Assessment of Greenhouse Gas Abatement from Wind Farms in Victoria*, Sustainability Victoria, July 2006. See http://www.sustainability.vic.gov.au/resources/documents/Greenhouse_abatement_from_wind_report.pdf.

5 International Energy Agency, *Hydropower and the Environment: Present Context and Guidelines for Future Action*, IEA Technical Report, 2000.

6 URS, *Environmental Impact Statement – Woodlawn Wind Farm*, Woodlawn WindEnergy Joint Venture, 2004.

7 The Australia Institute, *Wind farms: The facts and the fallacies*, 2006, p.17.

have the effect of increasing emissions since the use of FCAS means that any fossil fuel generators providing additional FCAS would be operating at levels below their maximum capacity, which is sub-optimal in terms of thermal efficiency and therefore results in increased emissions. However, the increase would be small, and in the words of the UK's Sustainable Development Commission

> [w]hen wind produces 20% of total output, it is estimated that the emissions savings from wind will be reduced by a little over 1%, meaning that 99% of the emissions from the displaced fuel will be saved[8].

Thus, it is likely that the emissions savings from displaced fossil fuel outweigh any additional emissions arising from the need for additional FCAS. The additional emissions from additional FCAS services are modelled in this study.

8 Sustainable Development Commission UK, *Wind Power in the UK: A guide to the key issues surrounding onshore wind power development in the UK,* Government of the UK, 2006, p.26.

4 METHODOLOGY AND ASSUMPTIONS OVERVIEW

The emissions abatement impact that wind farms will have in New South Wales is driven in part by the future generation mix, which is in turn driven by electricity demand, the carbon price and the expected level of renewable energy generation. The carbon price is a critical component in this equation as it drives the abatement of emissions, primarily through the retirement and/or winding down of coal plant production. However, with respect to renewable energy projects the carbon price has a lesser impact while the carbon price is insufficient to meet the renewable energy targets without additional certificate revenue. This is because any increase in carbon price raises electricity prices which then reduce certificate prices. The critical factors for renewable energy projects during this period are:

- The magnitude of the renewable energy target.
- The new renewable energy supply curve which will determine the new entry cost for renewable energy.
- The extent to which renewable resources are developed in areas of higher energy costs relative to other locations. Returns to wind farms in other locations would be reduced if REC prices are lower due to high energy prices elsewhere, such as in Western Australia.

4.1 Factors Considered

The electricity modelling developed for the NSW DECCW 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 more detailed exposition of the methodology and assumptions can be found in Appendix A.

4.2 PLEXOS Software platform

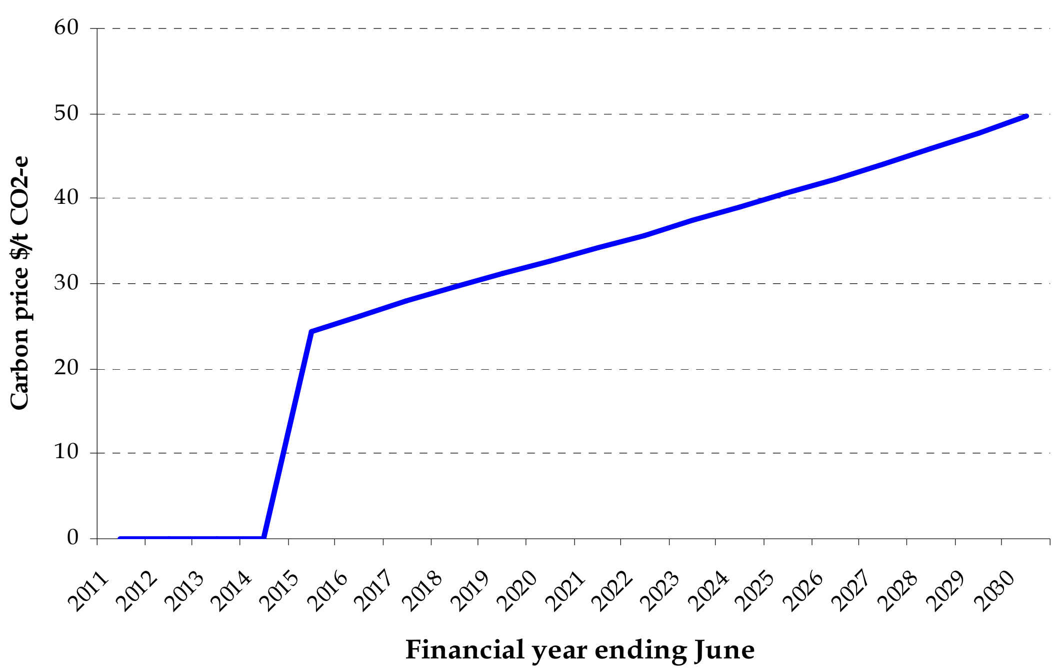
The wholesale market price forecasts will be developed utilising MMA's Monte Carlo NEM database. This database uses PLEXOS, a sophisticated stochastic mathematical model developed by Energy Exemplar which can be used to project electricity generation, pricing, and associated costs for the NEM. This model optimises dispatch using the same techniques that are used by AEMO to clear the NEM, and incorporates Monte-Carlo forced outage modelling. It also uses mixed integer linear programming to determine an optimal long-term generation capacity expansion plan.

4.3 Scenario assumptions

The present study consists of four scenarios, each with a different level of wind penetration in NSW. The first scenario is the baseline scenario, in which no new wind capacity enters NSW. In the second scenario 150 MW of wind capacity is forced into the NSW market for the whole modelling horizon. This capacity level was chosen as it represents the size of a large wind farm site. The third scenario models the addition of 500 MW of wind capacity in NSW, which represents the upper range of the wind capacity that would be expected to be installed in one of NSW's six wind farm precincts. Finally, the fourth scenario models the impact of 3,000 MW of additional wind capacity in NSW. This represents the installation of 500 MW of wind capacity in each of the six wind precincts, thus modelling the upper range of wind capacity that may be expected to eventuate in the NSW region.

All scenarios assume that the 5% emission reduction target for 2020 is adopted by the Government, although its implementation is delayed until July 2014. The carbon price path is shown in Figure 4-1, and is adapted from the CPRS-5% price path employed in the Federal Treasury modelling.

Figure 4-1 Carbon Price Path – delayed CPRS-5%



The dispatch model is structured to produce half-hourly price and dispatch levels for the entire year.

The base assumptions are common to all three scenarios and reflect the most probable market outcomes given the current state of knowledge of the market. They include medium energy growth as well as median peak demands, as provided in AEMO's 2009 Electricity Statement of Opportunities, (ESOO). The demand forecasts have been amended slightly to take account of differences in assumptions related to carbon prices in formulating the forecast, although the adjustment is quite minor at less than 0.3%.

Key features of the base assumptions include:

- Capacity is installed to meet the target reserve margin for the NEM in each region. Some of this peaking capacity may represent demand side response rather than physical generation assets.
- The medium demand growth projections with annual demand shapes consistent with the relative growth in summer and winter peak demand.
- Generators behaving rationally, with uneconomic capacity withdrawn from the market.
- The expanded RET scheme incorporates MRET and VRET state schemes for renewable energy. The target as legislated is for 41,000 GWh of renewable generation by 2020[9]. The expanded RET scheme remains similar to the existing old MRET scheme in terms of issues such as banking and project eligibility periods.
- The increase in the Queensland gas fired generation target to 18% by 2020 will be eventually replaced by the CPRS. In the meantime the target is increased from 13% at 0.5% per year from 2010. Even with \$10/tCO_2e carbon price, there is enough gas fired generation to meet the Queensland gas fired generation target and so the GEC price would go to zero.
- The assessed demand side response for emissions abatement or otherwise economic responses throughout the NEM is assumed to be included in the NEM demand forecast.
- Carbon capture and storage is not available until 2025/26. The long-term modelling for the Federal Treasury revealed that the threat of (relatively) low cost carbon capture and storage in the face of high carbon prices made problematic the entry of conventional CCGT plant in the medium term as a transitional base load technology. CCGTs would therefore only be commissioned sparingly, and only if prices are high enough to support a relatively rapid recovery of their fixed costs.
- Generation from any nuclear process is not available in the study period.
- Geothermal generation becomes commercially viable in 2017.

9 The RET scheme will be split into a large scale genration and small scale generation component. The ultimate target for the large scale cmponent is 41.000 GWh.

5 NEW RENEWABLE ENERGY AND EMISSION ABATEMENT

Modelling the NEM is no longer simply an exercise in determining the centrally coordinated dispatch of generation to meet demand at least cost. There are a number of greenhouse gas abatement measures that have been implemented by Federal and State governments in the past four to five years that impact on the dispatch of generation. Some schemes, such as the RET, facilitate renewable energy projects which displace scheduled thermal generation. Other schemes, such as the New South Wales Greenhouse Gas Abatement Scheme (GGAS) and the Queensland Cleaner Energy Strategy (CES), provide subsidies to gas-fired generation or other low-emission technologies and consequently lower the net marginal costs of these generators.

The major impact of these schemes has been to suppress wholesale electricity prices by prolonging the supply surplus through additional demand side management, renewable energy generation and advancement of gas fired generation. New entry prices are lower than in the absence of these schemes because gas fired plants have been able to obtain a subsidy of between $3 and $12/MWh depending on the supply/demand in these niche markets.

Of course the major development with respect to renewable energy generation has been the expansion of the RET scheme. The scheme is legislated, and its design has not changed substantially from the prior MRET scheme, in that unlimited banking of RECs is allowed, and there are no restrictions on project eligibility periods. The expanded RET is likely to bring on significant wind and biomass capacity over the next decade, which will meet a large proportion of the underlying demand growth. Substantial penetration of wind may require additional open cycle gas turbine plants to provide reserve capacity for when the wind is not blowing. In principle, these plants may displace to some degree combined cycle and new coal fired options that would be more economic without the wind eroding the base load role.

The Federal Government has now delayed the implementation of its emissions trading scheme, known as the CPRS, thus adding to the uncertainty surrounding emission trading. Even though there is less uncertainty about the emissions targets and their scope, carbon prices are still difficult to predict given the scheme's dependence on the outcome of international negotiations.

Table 5-1 Summary of environmental schemes influencing the NEM

Scheme	Objectives	Scope	NEM Impact	Future Prospects
Renewable Energy Certificates	To bring 41,000 GWh of additional renewable electricity generation into Australia by 2020 through a retailer / large user obligation to purchase an increasing proportion of renewable energy.	All electricity grids exceeding 100 MW in size (NEM, WA, NT)	Adds about 8,000 MW of new capacity and delays the requirement for conventional thermal plant. Places a lid on pool prices in early years as most of the new plants are price takers (wind, biomass, additional hydro).	No change in the target beyond 2020 unless otherwise altered by new policies.
Queensland Gas Electricity Certificates	Increase gas fired electricity supply in Queensland to 13% of electricity consumption excluding some price sensitive large loads greater than 750 GWh per annum. The target has been increased to 18% but the timing is currently unclear[10].	All gas fired electricity located in Queensland with some limited scope for participation for imported power.	Will encourage some additional capacity into Queensland and lower the bid prices of gas fired generation mainly during shoulder periods when additional Gas Certificates are required.	No change – expected to be made redundant through CPRS.
NSW Greenhouse Gas Abatement Program	Mandatory targets for GHG emission intensity on a per capita basis from 2003 to 2020 for NSW retailers to reduce GHG emissions from power generation.	All electricity in NSW purchased from the NEM. Generators outside NSW may participate.	Will stimulate gas fired generation throughout the NEM plus some demand side management in NSW. This will have the effect of lowering energy prices.	Will cease when CPRS commences.

10 The sculpting of the scheme target to 18% is currently unclear. Initial studies have been conducted with an immediate increase to 18% with GEC price at the cap, but on refection we consider that it would be more like 13% in 2010 rising at 0.5% per annum to 18% by 2020. This would be a more practical assumption.

For the purpose of this study, MMA has utilised the carbon prices that emerged from the Federal Treasury modelling for the CPRS-5% scenario, although the scheme's implementation has been delayed until July 2014.

With the introduction of the CPRS, electricity prices will no longer be suppressed through subsidies provided to gas-fired generation or other low-emission technologies. On the contrary, the carbon price will be an additional cost to generators that will be passed through to end-users. Analysis to date suggests that the average wholesale electricity price could increase between 50% and 100% of the carbon price.

5.1 Renewable energy scheme

5.1.1 Expanded RET scheme

The Commonwealth Government's new policy is to achieve 20% additional renewable energy by 2020. It has been legislated as a 41,000 GWh target with a maximum penalty for non-performance of $65/MWh. This penalty is not indexed to CPI. The penalty is also not tax deductible, meaning that under current company tax rates a liable party would be indifferent between paying the penalty or purchasing certificates at a price of $93/MWh.

To model the expanded RET scheme, it has been assumed that the current scheme for MRET would continue to operate with an increased target from 2010 onwards, and with an increase in the penalty price for non-compliance. The targets are shown in Table 5-2. The 41,000 GWh target continues until 2030.

For the purpose of PLEXOS modelling, it is important to note that this is a national renewable energy target rather than a NEM-wide target. Moreover, not all eligible renewable energy sources are modelled explicitly in PLEXOS. Therefore, it was necessary to derive a NEM equivalent renewable energy target taking account of the expected contribution from other sources including:

- Renewable energy sources from Western Australia and the Northern Territory.
- Solar water heater sales.
- Small generation units.
- Eligible existing and committed biomass and small hydro generation.
- Green Power sales, which effectively increase the total renewable energy requirements.
- Additional renewable energy demand created by the promise that desalination plants in Victoria, NSW and South Australia would source their energy from renewable sources.

Where renewable sources contribute towards the NEM native demand[11], load was modified based on the assumed levels of generation from these sources. Up to 3,500 GWh of electricity demand is assumed to be displaced by solar water heaters annually.

The annual renewable energy targets included in MMA's NEM database take these considerations into account, but also include baseline hydro generation from existing hydro schemes.

Table 5-2 Required GWh from renewable energy sources to meet expanded LRET

Calendar Year	Target (GWh)
2009	8,678
2010	12,500
2011	10,400
2012	12,300
2013	14,200
2014	16,100
2015	18,000
2016	22,600
2017	27,200
2018	31,800
2019	36,400
2020 - 2030	41,000
2031	0

5.1.2 Renewable energy supply curve

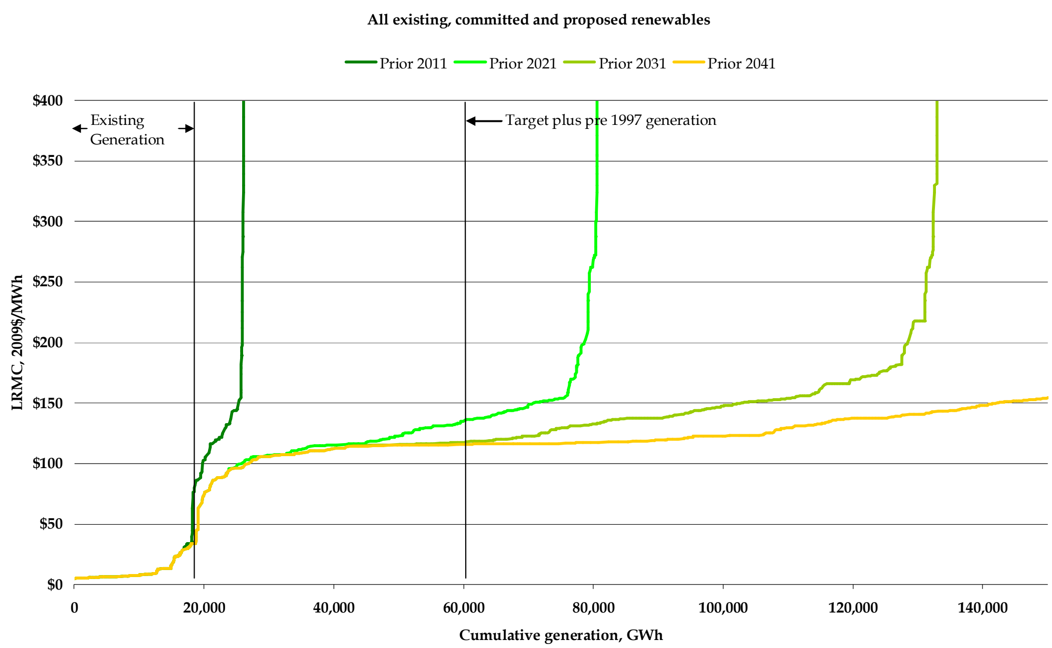
For the purposes of forecasting renewable energy prices, a critical requirement is the database of potential renewable energy projects. MMA has developed a database which includes existing, committed, and prospective projects including some allowance for generic projects based on projections by industry organisations. With the current tightening of the global financial system, we have assumed project financing costs based on a debt level to 60%, and have also added on a 1% premium to return on debt, reflecting the increased scarcity of capital funding, bringing to it 7.3% in real terms. Under these assumptions the resulting WACC is 11.0%, which is applied from 2010 trending back to the normal level of 9.3% by 2014.

Figure 5-1 shows the cumulative renewable energy supply curve developed from the database including the existing and committed plants. The supply curve includes all resources expected to be available until 2040. This shows that at 41 TWh, the marginal

11 For example, solar water heater uptake under the small scale renewable energy scheme.

cost is about $115/MWh. The actual renewable energy cost by 2020 will be higher because some of the resources shown in Figure 5-1 will be available at this cost until well after 2020.

Figure 5-1 Renewable Energy Supply Curve to 2040



The equivalent curve for only wind farms is shown in Figure 5-2[12]. Most of the available wind projects are in the cost range of $110 to $140/MWh. The higher cost wind farms will be displaced by the development of other renewable energy technologies.

In 2007/08, wind turbine costs had increased at a significant rate due mainly to demand for wind turbines and the large increase in the cost of steel. However, with the onset of the global financial crisis, these cost pressures have eased because demand has fallen significantly and metal prices have fallen since their peak. The fall in metal prices has been offset to a degree by the decline in the Australian dollar, but the net effect is that capital costs are where they were before the 2007/08 price spike.

The geothermal supply curve for both scenarios is shown in Figure 5-3. Geothermal is priced at $4,300/kW plus approximately $26/MWh plus up to $750/kW for transmission cost. Real capital cost reductions are set at 0.7% per year.

The solar thermal supply is shown in Figure 5-4. These resources are not available until after 2020 and the low cost assumes that production capacity is scaled up to produce about 50 to 75 MW of capacity per year. The current cost is about $6,000/kW decreasing

[12] Capital costs for wind turbines range from $2000 to $5000/kW (typically $2200 to $3000/kW) plus transmission connection capital costs from $100 to $500/kW. Capital costs trend at CPI-0.4%.

at CPI-2%. It is expected that economies of scale of production will eventually reduce capital costs. The same supply curve is used for both scenarios.

Figure 5-2 Wind Energy Supply Curve

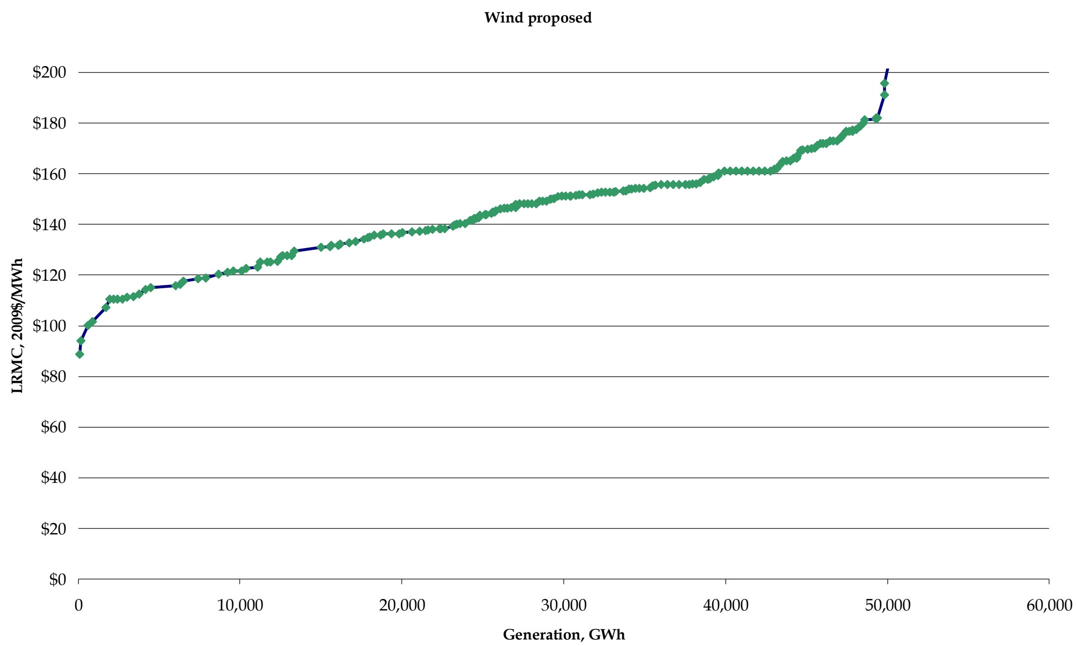


Figure 5-3 Geothermal Energy Supply Curve

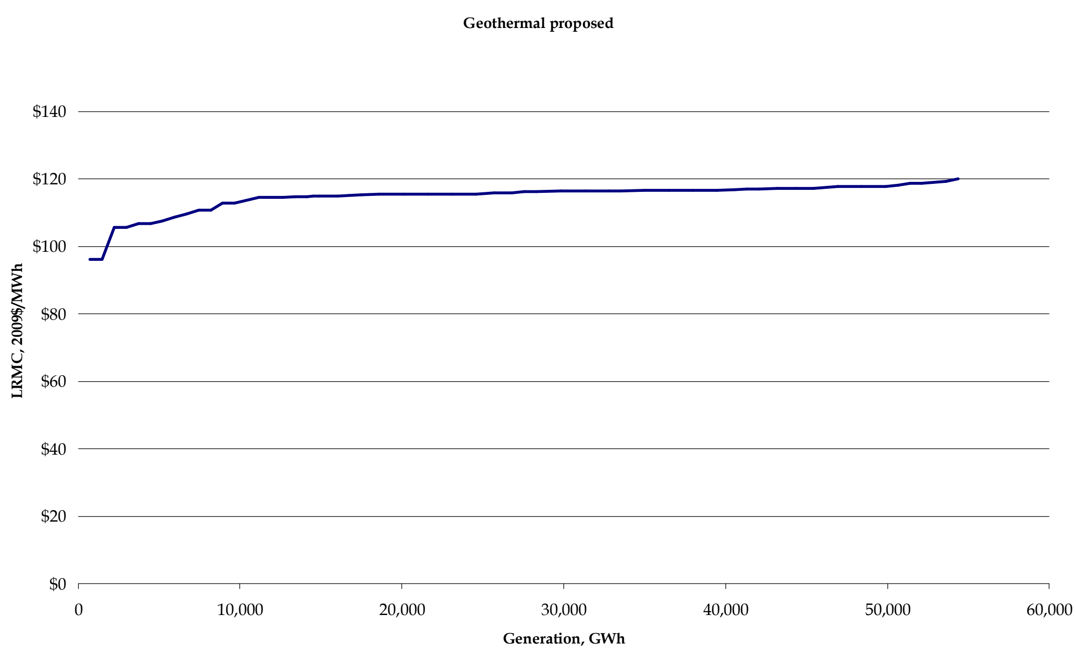
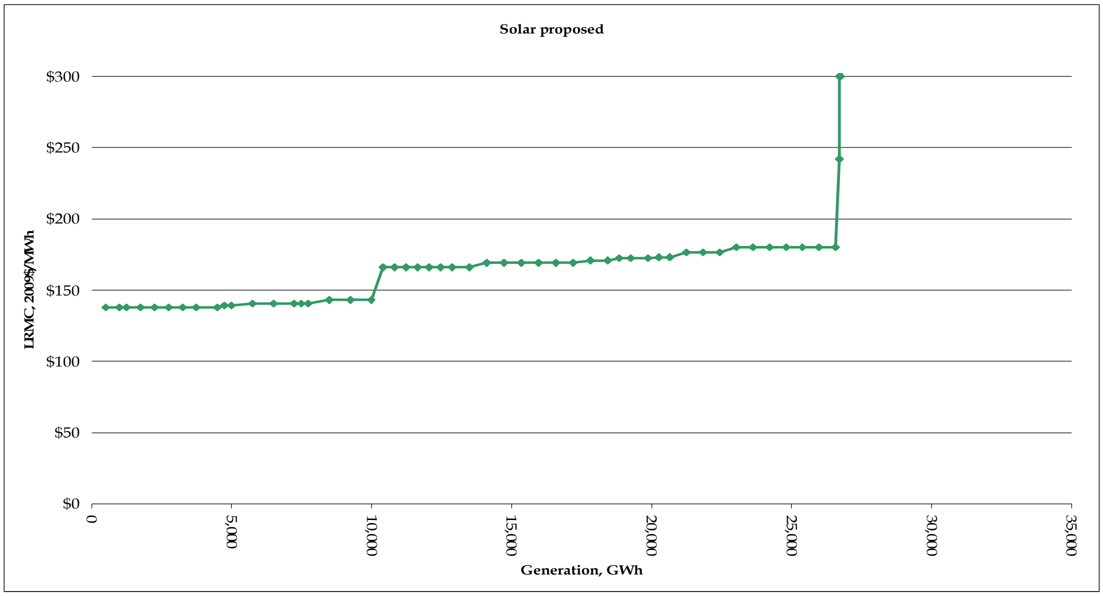


Figure 5-4 Solar Thermal Energy Supply Curve



5.2 NSW Greenhouse Gas Abatement Scheme

The NGGAS scheme is expected to finish just prior to emission trading, and it was previously assumed that the NSW Greenhouse Abatement Certificates (NGACs) traded under the NGGAS would be given full value as emission credits equal to 1 tonne of CO_2. This is now unlikely to happen, and NGAC prices are expected to remain low.

The NSW Government's has announced that the scheme will continue to operate until 2025 unless an emissions trading scheme is implemented. The Federal Government is expected to introduce the CPRS after 2013, and the New South Wales Government committed to undertake a 'smooth transition between the two schemes'[13] in order to compensate for revenue losses from NGAC creations.

Given the limited horizon of the NGAC scheme assuming that it is superseded by the CPRS, MMA's NGAC price projection for the present study is based on the NGAC spot price and the forward curve. This is presented below in Table 5-3. The prices were derived from forward prices in March 2010 and adjusted back to June 2009 dollars.

Table 5-3 NGAC prices ($/t CO_2-e) assumed for present study (June 2009 dollars)

Year ending June	NGAC Price
2011	4.30
2012	4.48
2013	4.50
2014	4.50

[13] NSW Department of Water and Energy. (2008). *Transitional arrangements for the NSW Greenhouse Gas Reduction Scheme – Consulation paper*. ((http://www.dwe.nsw.gov.au)

5.3 Gas Electricity Certificates Scheme in Queensland

In May 2000, the Queensland Government announced the Queensland Energy Policy – A Cleaner Energy Strategy. A key initiative of the Energy Policy is the Queensland Gas Electricity Scheme. This scheme requires electricity retailers and other liable parties to source at least 13% of their electricity from gas-fired generation from 1 January 2005.

The Gas Electricity Scheme is a certificate based scheme consisting of:

- Accredited Parties – generators of eligible gas-fired electricity who can create Gas Electricity Certificates (GECs), which have value and can be traded separately to the electricity to which they relate; and
- Liable Parties (largely electricity retailers and others that sell electricity to end users) - parties who are required to surrender GECs to the Regulator to acquit a liability.

Liabilities may be incurred by parties who are connected to, or sell to end users connected to, a major grid. A major grid is defined as a grid with an installed capacity which exceeds 100 MW. There are currently two Queensland grids that fit this description, the National Grid and the Mica Creek Grid, which supplies electricity to the Mount Isa region.

The target was to be modified to 18% by 2020 by the Queensland Government. However, with the more recent commitment to emissions trading, the new target is proposed to be 15% by 2010. Post July 2011, it is expected that there will be a transition to the CPRS and the target with become redundant. Where emissions trading is deferred, it is assumed that the target will be increased linearly toward 18% by 2020.

Given the limited horizon of the GEC scheme assuming that it is superseded by the CPRS, MMA's GEC price projection for the present study is based on the GEC spot price and the forward curve, which is presented below in Table 5-4. The price are expected to be relatively low as subdued gas price mean a significant and growing proportion of Queensland generation will be gas-fired.

Table 5-4 GEC prices (June 2009 dollars)

Year ending June	CPRS Jul-11
2011	2.65
2012	2.69
2013	2.74
2014	2.78

6 RESULTS

The PLEXOS models were set up in the four scenarios (baseline, 150 MW of wind in NSW, 500 MW of wind in NSW, and 3,000 MW of wind in NSW) to run from July 2010 until June 2020. These simulations were based on marginal cost bidding since prices were not a critical output. Moreover, the simulations modelled the market chronologically in 30 minute time steps, and also modelled ramping restrictions of power stations within this time frame in order to capture the effect that a sudden drop in wind may have on the dispatch, and in particular, the fuel mix. Up to 5 Monte Carlo simulations (samples) were run within the time frame of the present assignment.

6.1 Emissions abated

Figure 6-1 shows the annual amount of emissions abated in NSW for the 150 MW case, the 500 MW case and the 3,000 MW case, all relative to the baseline scenario. There is a noticeable drop in abatement levels from 2015 onwards, which coincides with the introduction of the CPRS. This means that wind is displacing less coal-fired generation and more gas-fired generation post 2015 since the positive carbon price makes coal less competitive. The relatively high level of variability in abatement for the 150 MW case is the result of sampling factors. Each Monte Carlo sample has a different forced outage pattern, resulting in random variations in total emissions production. For the 150 MW case, this random variation in total NSW emissions is comparable to the level of emissions abated by the 150 MW of wind farm capacity.

Figure 6-1 Emissions abated in NSW for the 150 MW, 500 MW and 3,000 MW cases

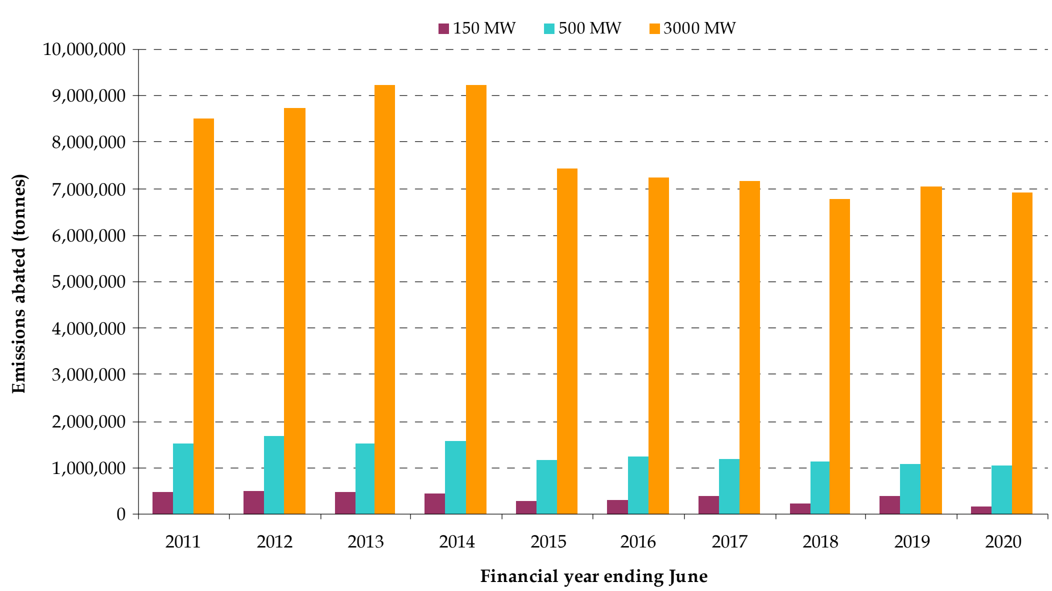


Table 6-1 Emissions saving by region by scenario relative to Baseline scenario (kt per annum)

Region ►	Region 1		Region 2		Region 3		Region 4		Region 5		Region 6	
Region Name ►	New England Tablelands		Upper Hunter		Central Tablelands		NSW/ACT Border Region		South Coast		Cooma-Monaro	
Scenario ►	150 MW	500 MW	150 MW	500 MW	150 MW	500 MW	150 MW	500 MW	150 MW	500 MW	150 MW	500 MW
2011	434	1,375	414	1,311	431	1,363	436	1,381	374	1,184	440	1,393
2012	447	1,534	426	1,466	443	1,521	448	1,540	385	1,331	452	1,553
2013	419	1,364	400	1,300	416	1,352	421	1,370	361	1,175	425	1,382
2014	391	1,422	373	1,356	387	1,409	393	1,428	337	1,224	396	1,441
2015	260	1,053	248	1,004	258	1,044	261	1,057	224	907	263	1,067
2016	281	1,110	268	1,058	278	1,100	282	1,115	242	956	284	1,125
2017	357	1,075	341	1,025	354	1,066	359	1,080	308	926	362	1,090
2018	200	1,027	190	979	198	1,017	200	1,031	172	884	202	1,040
2019	356	968	340	923	353	959	358	972	307	833	361	981
2020	146	950	139	905	145	941	147	954	126	818	148	962

Table 6-1 shows the emissions savings (as is depicted in Figure 6-1) by wind region for the two regional wind scenarios (150 MW and 500 MW cases). The savings in these cases are slightly less than those depicted in Figure 6-1 since the capacity factors of the regional wind farms were lower than the historical profiles that were used in the modelling. Most abatement occurs for wind farms located in the Cooma-Monaro region, which is mainly due to favourable MLFs in the region. On the other hand, the least abatement takes place for wind farms located in the South Coast region, mainly because the quality of wind resources are not as good as the other regions.

Figure 6-2 shows the emissions abated for the three wind cases[14] as a percentage of the total emissions that could be expected to be abated if all of the wind farm output displaced the baseline generation mix (i.e. a mix that corresponded to the average annual NSW emissions intensity factor for the baseline scenario)[15]. Pre 2015, this percentage is high (93% on average) since the new wind farms would generally be displacing coal plant. The exception here occurs in 2011 and 2012 for the 3,000 MW case, where about 4% of the additional wind energy is used for pumping at Shoalhaven and Upper Tumut, thus creating additional demand, which is filled by black coal. The percentage of wind energy abated drops to below 80% post 2015 when the CPRS commences. In this period wind displaces a greater proportion of gas-fired generation, which has a significantly lower emissions intensity factor than coal-fired generation. Figure 6-2 shows that the emissions savings generally reduce as the carbon price increases, but that the savings are still significant, ranging from 71% to 76% of the wind farm's output post 2015 for the 3,000 MW case, from 67% to 76% for the 500 MW case, and from 57% to 68% for the 150 MW case.

A more detailed picture on the dynamics of emissions abatement resulting from wind capacity is presented in Appendix C, which shows the emissions abatement profile of a typical week.

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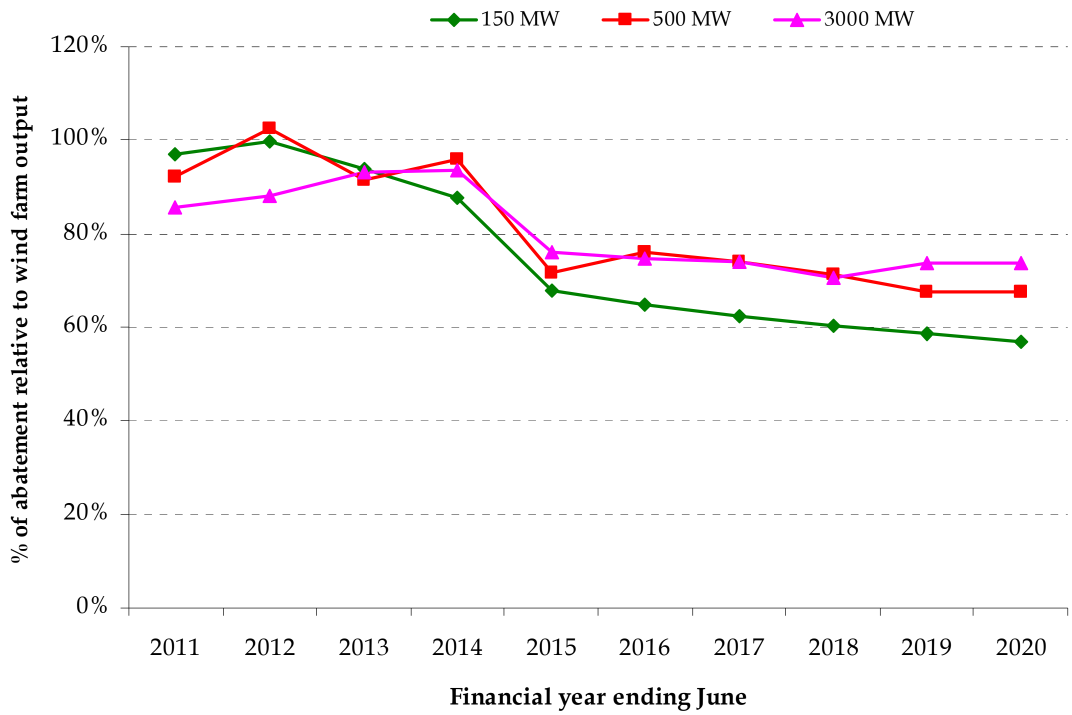
14 The data for the 150 MW case has been smoothed from 2015 onwards to better show the trend of abatement.

15 The savings of 102% in 2012 for the 500 MW case indicates that the wind generation is displacing a generation mix with a higher emissions intensity than the average Baseline generation mix.

Figure 6-2 Emissions abated relative to wind farm output and baseline emissions intensity



6.2 NSW trends in emissions intensity from power generation

Figure 6-3 shows total NSW emissions from power generation by scenario. The plateau reached in 2014 is a result of increased penetration of renewable generation, as encouraged by the RET scheme. Emissions continue to climb once the CPRS commences. This occurs for a number of reasons: (i) the introduction of a carbon price results in the closure of brown goal generation units in Victoria and NSW black coal generators run harder in order to export more energy into Victoria; (ii) the NSW black coal generators have lower marginal costs relative to the Victorian brown coal generators once a significant carbon price (above \$20/t CO_2e) is introduced, and now export to Victoria overnight, hence increasing their generation and their emissions; (iii) demand continues to increase, although renewable energy pick up most of the growth[16].

[16] Emissions projections for NSW are distorted by the fact that only 150 MW and 500 MW of wind have been introduced in the 150 MW and 500 MW wind scenarios. In MMA's usual modelling, over 1,500 MW of wind is normally installed in NSW and this has a significant impact on emissions.

Figure 6-3 Total emissions from power generation in NSW by scenario

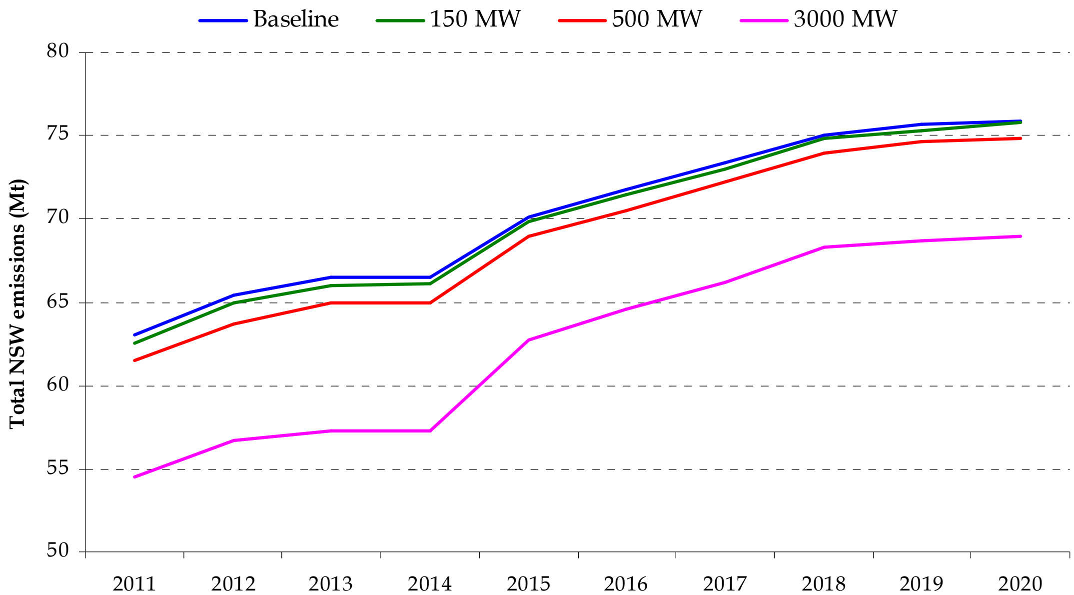


Figure 6-4 shows the NSW emissions intensity factor by scenario. Even though emissions are increasing, the average emissions intensity for power generation decreases over the same time frame. The exception here is the 3,000 MW case, where the large block of wind energy has rendered the emissions intensity profile fairly flat. The effect of the introduction of the CPRS in FY 2015 on the emissions intensity is clearly apparent for the first three scenarios, since the downward trend in emissions intensity accelerates from this point onwards. The major factors driving the reduction in emissions intensity are (i) increased penetration of renewable generation sources[17]; (ii) increased dispatch of existing lower emissions gas plants, and Colongra GTs, and the commissioning of new low emission gas turbine power stations. These points are illustrated in Figure 6-5, which shows that both gas-fired and renewable generation is growing at a faster rate than coal-fired generation. Figure 6-6 also demonstrates the same point since it shows the market share of coal-fired generation decreasing, and that of gas-fired and renewable generation increasing. Figure 6-7 has also been included to indicate what the market shares by fuel type would look like for a more realistic level of NSW installed wind capacity. In this case the market share of renewable generation in more in line with the 20% expanded RET target. The market share of coal fired generation is around 80% to 83% (see Figure 6-7) compared with 91% to 96% when there is no wind generation in NSW (see Figure 6-6).

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17 The increase is due to generation from new renewable energy generator other than wind, bought on by the expand RET scheme.

Figure 6-4 NSW emissions intensity by scenario

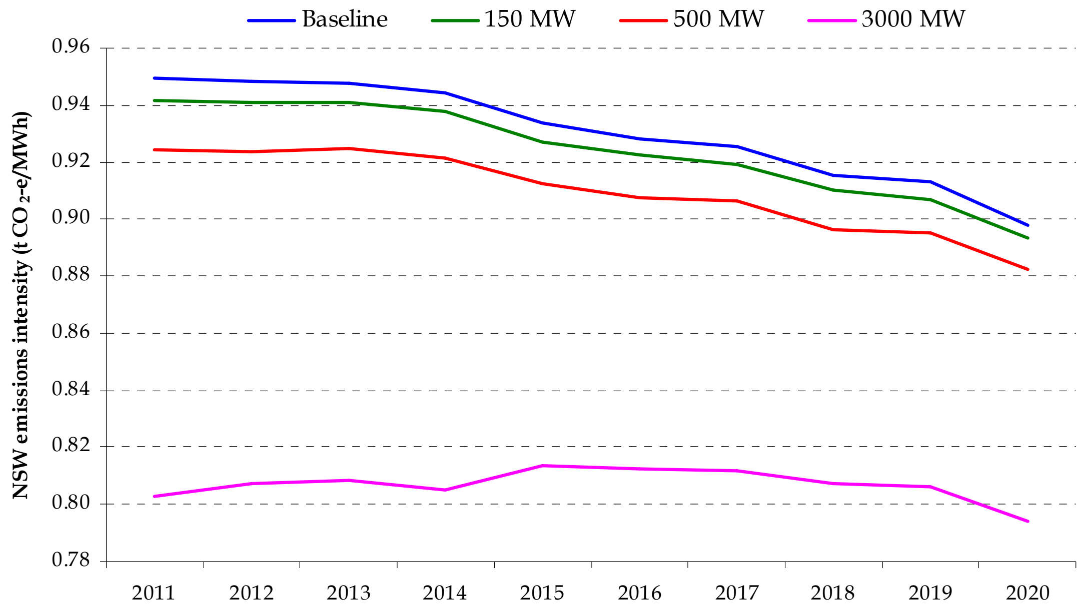


Figure 6-5 Growth in NSW generation categories relative to 2011, baseline scenario

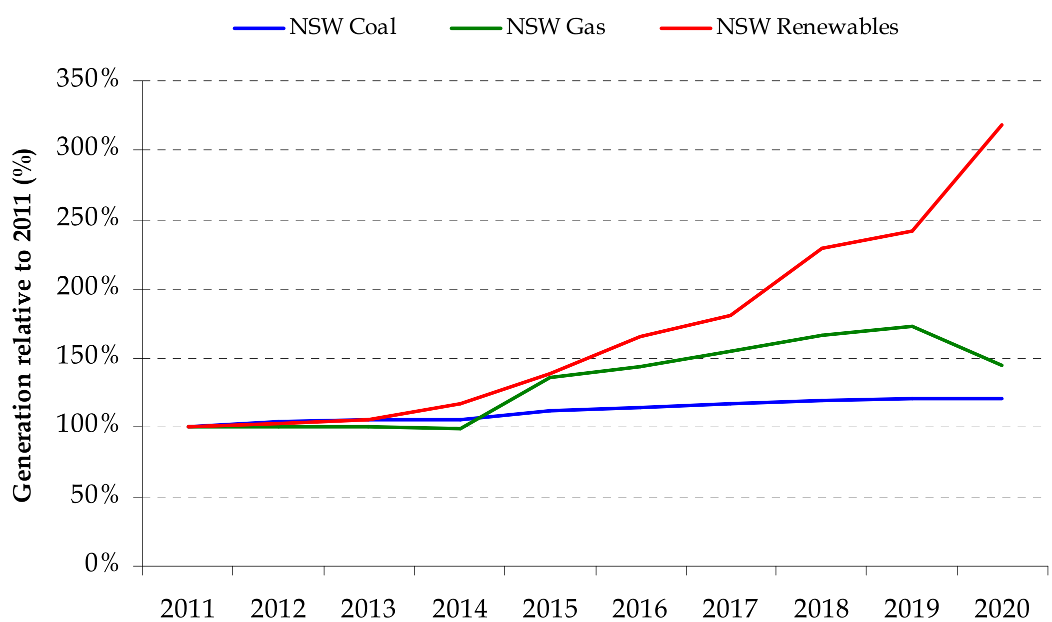


Figure 6-6 NSW power generation market shares by fuel type, baseline scenario

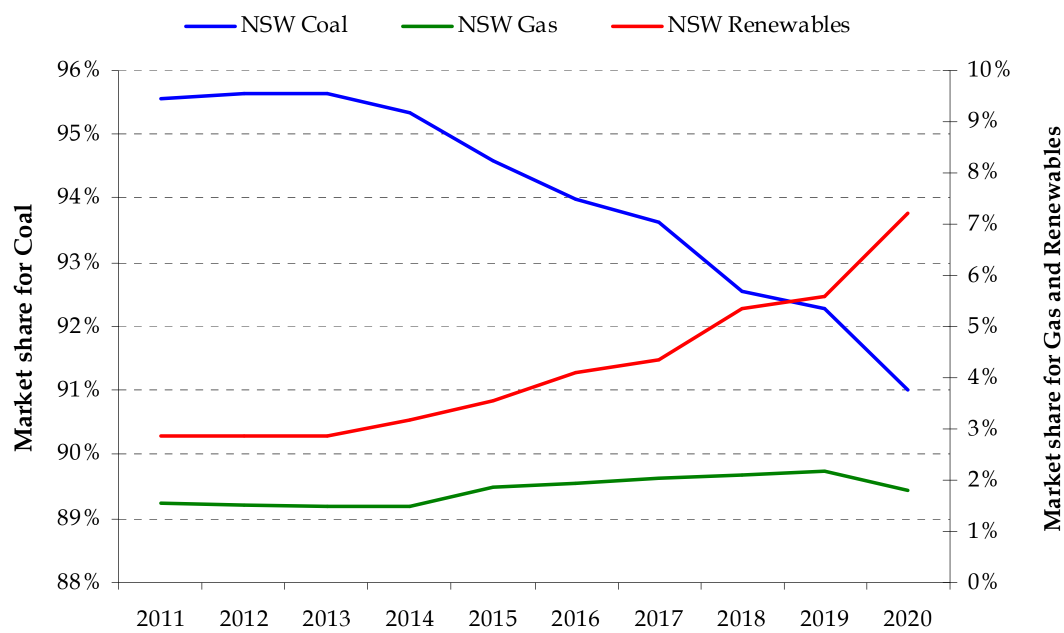
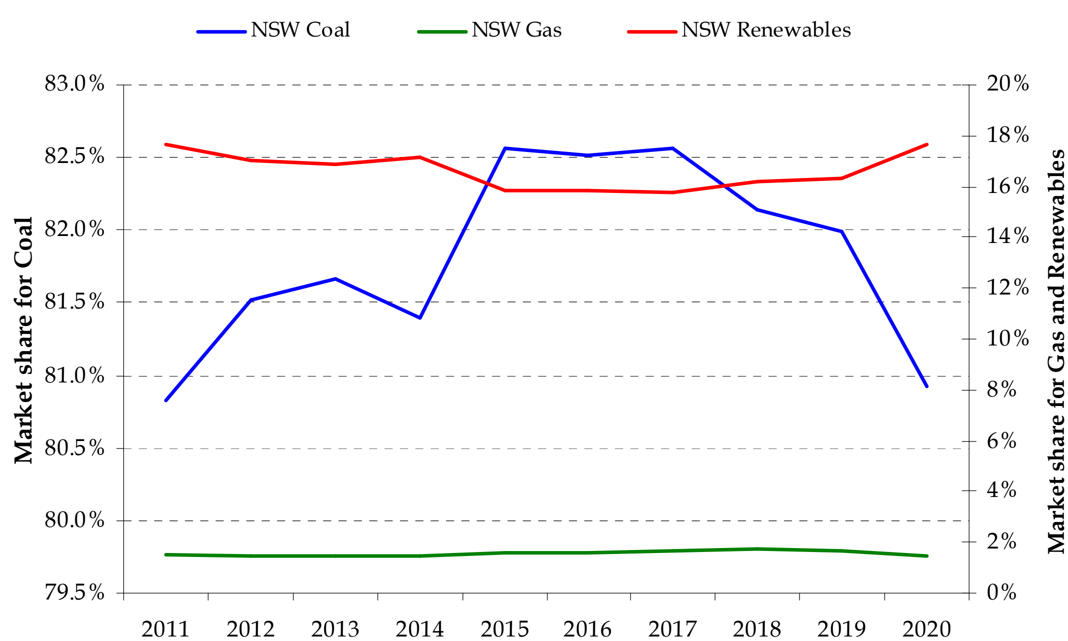


Figure 6-7 NSW power generation market shares by fuel type, 3,000 MW scenario



Note the difference in scales between Figure 6.6 and Figure 6.7.

The relative change in emissions intensity between scenarios explains why the generation from additional wind farm capacity does not result in 100% emissions abatement from that capacity (see Figure 6-2). Figure 6-8 shows the market share of gas-fired generation in NSW by scenario. The market share clearly separates between the four scenarios after the introduction of the CPRS, and this is due to the fact that in a CPRS environment the additional wind capacity for the 150 MW, 500 MW and 3000 MW wind scenarios displaces some gas-fired generation, which has much lower emissions intensity than coal-fired generation.

Figure 6-8 Market share of NSW gas-fired generation by scenario

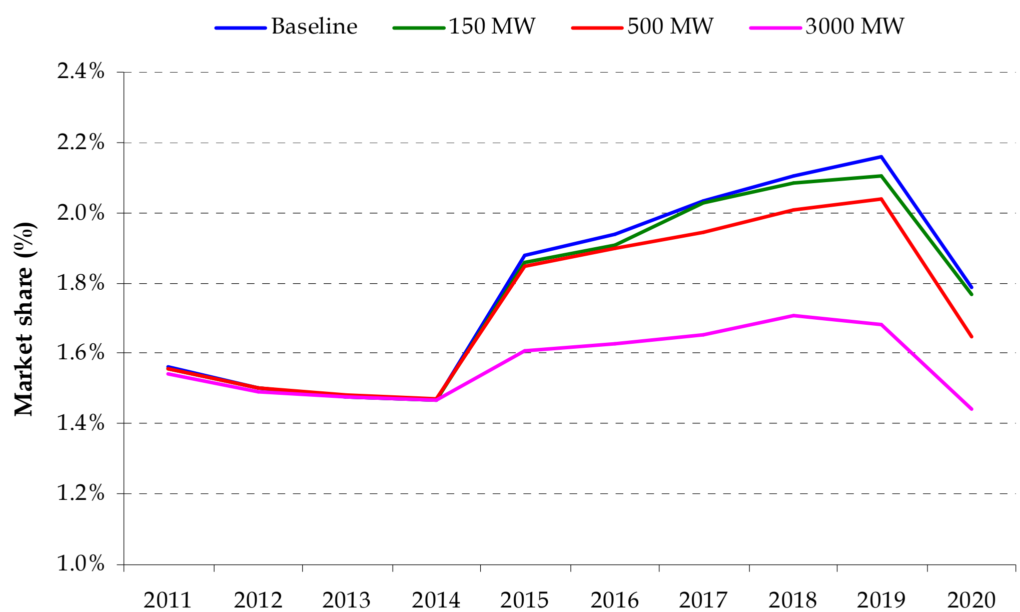


Figure 6-9 and Figure 6-10 illustrate the difference in NSW coal-fired generation between the baseline scenario and the three wind scenarios. There is a clear step down in the difference for all three wind scenarios once the CPRS commences. Moreover, the 500 MW and 3,000 MW cases clearly exhibit a further decline in the difference as the carbon price increases. This trend is also present in the 150 MW case, but to a lesser extent. Thus, wind displaces less coal-fired generation in a CPRS environment since as Figure 6-8 demonstrates, it also displaces some gas-fired generation.

Figure 6-9 Reduction in Output of NSW coal-fired generation between baseline scenario and 150 MW and 500 MW wind scenarios[18]

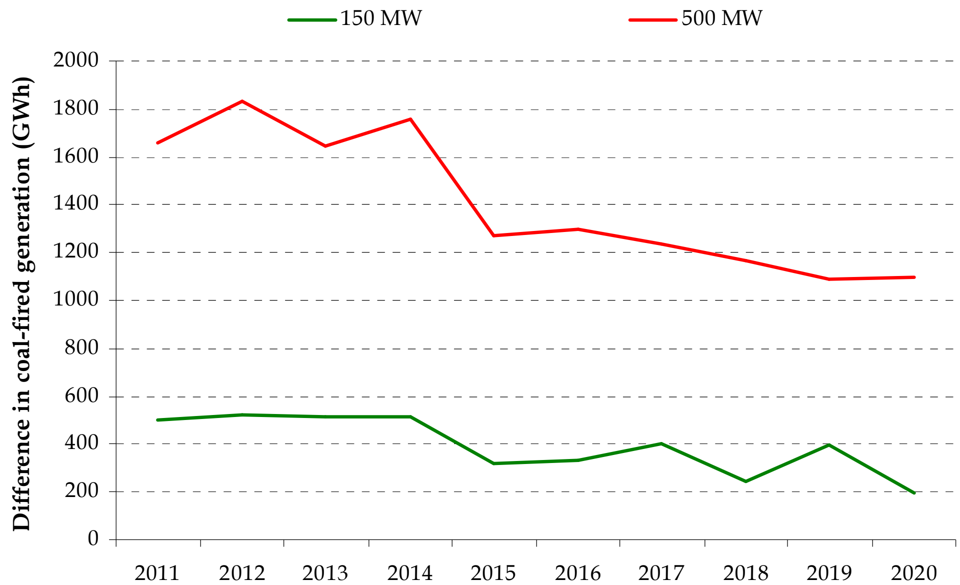
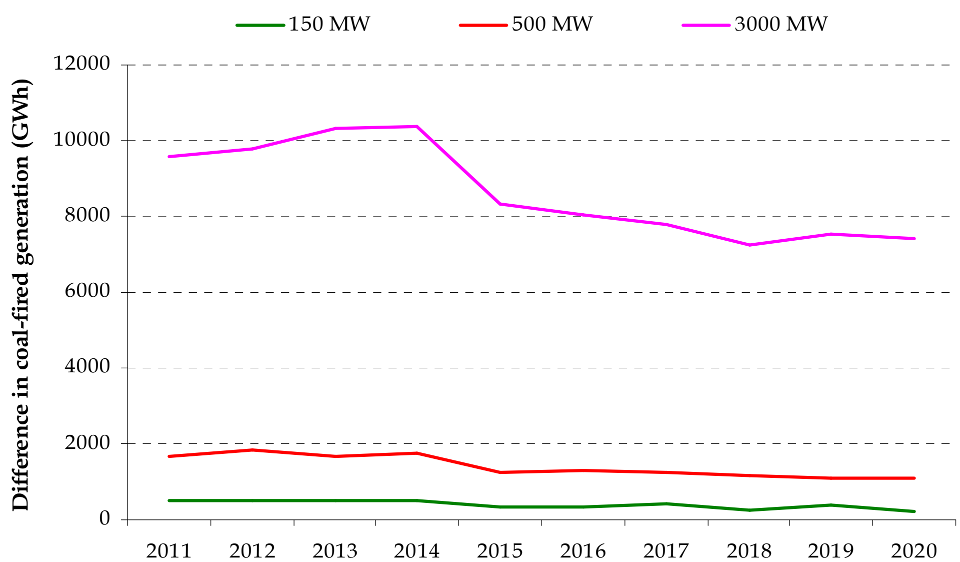


Figure 6-10 Difference in NSW coal-fired generation between baseline scenario and all wind scenarios



18 These two wind scenarios are shown here without the 3000 MW case for clarity. The next figure shows the output for all three wind scenarios.

APPENDIX A METHODOLOGY AND ASSUMPTIONS IN DETAIL

The emissions abatement impact that wind farms will have in New South Wales is driven in part by the future generation mix, which is in turn driven by electricity demand, the carbon price and the expected level of renewable energy projects. The carbon price is a critical component in this equation as it drives the abatement of emissions, primarily through the retirement and/or winding down of coal plant production. However, with respect to renewable energy projects, the carbon price has a lesser impact while the carbon price is insufficient to meet the renewable energy targets without additional certificate revenue. This is because any increase in carbon price raises detailing prices which then reduce certificate prices. The critical factors for renewable energy projects during this period are:

- The magnitude of the renewable energy target.
- The new renewable energy supply curve which will determine the new entry cost for renewable energy.
- The extent to which renewable resources are developed in areas of higher energy costs relative to other locations. Returns to wind farms in other locations would be reduced if REC prices are lower due to high energy prices elsewhere, such as in Western Australia.

A.1 Factors Considered

The market forecasts to be developed for the NSW DECCW 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 PLEXOS Software platform

The wholesale market price forecasts were developed utilising MMA's Monte Carlo NEM database. This database uses PLEXOS, a sophisticated stochastic mathematical model developed by Energy Exemplar which can be used to project electricity generation, pricing, and associated costs for the NEM. This model optimises dispatch using the same techniques that are used by AEMO to clear the NEM, and incorporates Monte-Carlo forced outage modelling. It also uses mixed integer linear programming to determine an optimal long-term generation capacity expansion plan.

The long-term capacity expansion model in PLEXOS 5 is called "LT Plan". The purpose of the LT Plan model is to find the optimal combination of generation new builds and retirements and transmission upgrades that minimises the net present value of the total costs of the system over a long-term planning horizon. That is, to simultaneously solve a generation and transmission capacity expansion problem and a dispatch problem from a, long-term perspective. Planning horizons for the LT Plan model are user-defined and are typically expected to be in the range of 20 to 30 years.

Once the capacity expansion plan has been determined, PLEXOS can then perform more detailed simulations, typically one year at a time, to more accurately model system dispatch and pricing. Prior to optimising dispatch in any given year, PLEXOS schedules planned maintenance and randomly pre-computes a user-specified number of forced outage scenarios for simulation. Dispatch is then optimised on an hourly basis for each forced outage sequence, given the load characteristics, plant capacities and availabilities, fuel restrictions and take-or-pay contracts, variable operating costs including fuel costs, inter-connector constraints and any other operating restrictions that may be specified.

Expected hourly electricity prices for the NEM are produced as output, calculated either on a marginal cost bidding basis, or if desired, by modelling strategic behaviour, based on gaming models such as the Cournot equilibrium, long-run marginal cost recovery (or revenue targeting) or shadow pricing.

The impact of financial contracts on the bidding strategy of market participants can be incorporated either explicitly through specification of volumes and prices of individual contracts, or implicitly by specifying a proportion of a portfolio’s output that is typically contracted, and hence restricting strategic bidding to the uncontracted proportion.

There are four key tasks performed by PLEXOS:

- Forecast demand over the planning horizon, given a historical load profile, expected energy generation and peak loads.
- Schedule maintenance and pre-compute forced outage scenarios.
- Model strategic behaviour, if desired, based on dynamic gaming models.
- Calculate half-hourly unit dispatch given the load characteristics, plant capacities and availabilities, fuel restrictions and take-or-pay contracts, other operating restrictions (such as meeting spinning reserve requirements and ramp rate restrictions) and variable operating costs including fuel costs and price impacts of abatement schemes.

The model can estimate:

- Half-hourly, daily, weekly and annual generation levels, operating costs, fuel usage and capacity factors for individual units.

- Regional generation and prices for each trading period.
- Flows on transmission lines for each trading period.
- Total costs of generation and supply in the NEM including capital costs of generation, fixed and variable fuel costs, and fixed and variable non-fuel operating costs. This can be done for the system as a whole, for generation companies operating in the system and for each generating plant.
- Reliability, which can be measured in terms of expected energy not served and expected hours of load shedding.
- Company and generator costs and operating profits.
- Emissions of greenhouse gases. Emissions for each fuel type are modelled to get total system emissions.

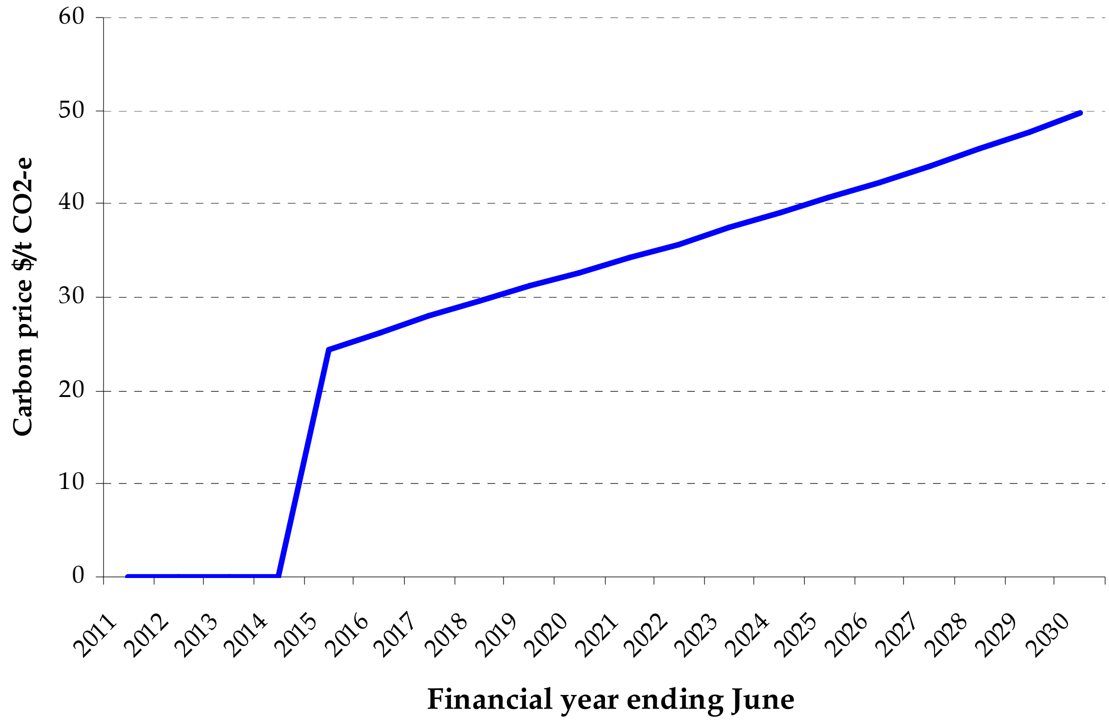
One of the key advantages of this model is the detail in which the transmission constraints of electricity grids can be modelled. The PLEXOS model includes 5 regions: Tasmania, South Australia, Victoria, New South Wales, and Queensland. Inter-regional transmission constraints and the dispatch impacts of intra-regional transmission constraints are modelled using the constraint set provided by AEMO as used in the Annual National Transmission Statement (ANTS). These constraints are dynamic with the limits typically being a function of regional demand, flows on other lines, inertia, number of units generating, and generation levels of relevant units. AEMO currently provides parameters for these constraints to 2020, and has also included a list of possible augmentations and the impact of these on the constraint set.

A.3 Scenario assumptions

This section details the assumptions underlying the three scenarios for this study. The first scenario is the baseline scenario, in which no new wind capacity enters NSW. In the second scenario 150 MW of wind capacity is forced into the NSW market for the whole modelling horizon. This capacity level was chosen as it represents the size of a large wind farm site. The third scenario models the addition of 500 MW of wind capacity in NSW, which represents the upper range of the wind capacity that would be expected to be installed in one of NSW's six wind farm precincts.

All scenarios assume that the 5% emission reduction target for 2020 is adopted by the Federal Government, although its implementation is delayed until July 2014. The carbon price path is shown in Figure A-1, and is adapted from the CPRS-5% price path employed in the Federal Treasury modelling.

Figure A-1 Carbon Price Path – delayed CPRS-5%



The dispatch model is structured to produce half-hourly price and dispatch forecasts for the entire year.

Common assumptions for all scenarios reflect the most probable market outcomes given the current state of knowledge of the market. They include medium energy growth as well as median peak demands, as provided in AEMO's 2009 Electricity Statement of Opportunities, (ESOO). The demand forecasts have been amended slightly to take account of differences in assumptions related to carbon prices in formulating the forecast, although the adjustment is quite minor at less than 0.3%.

Key features of the base assumptions include:

- Capacity is installed to meet the target reserve margin for the NEM in each region. Some of this peaking capacity may represent demand side response rather than physical generation assets.
- The medium demand growth projections with annual demand shapes consistent with the relative growth in summer and winter peak demand.
- Generators behaving rationally, with uneconomic capacity withdrawn from the market.
- Moomba to Sydney gas pipeline tariffs are consistent with the July 2002 submission to the ACCC by the Australian Pipeline Trust (APT).

- The Gunns pulp mill load and generation is not included in these scenarios as it is not apparent in the 2009 Tasmanian demand forecast.

Emissions abatement

- The Mandatory Renewable Energy Target (MRET) commenced on 1 April 2001, and was designed to integrate a renewable energy industry within the electricity market. The Australian Government's policy to achieve 2% additional renewable energy by 2010 has been implemented as a 9,500 GWh target with a maximum penalty for non-performance of $40/MWh post-tax which corresponds to $57/MWh pre-tax. The renewable energy scheme is discussed in more detail in Section 5.

  The expanded RET scheme incorporates MRET and VRET. The target as legislated is for 41,000 GWh of renewable generation by 2020. The new expanded RET scheme remains similar to the existing scheme in terms of issues such as banking and project eligibility periods.

- It was assumed that the increase in the Queensland gas fired generation target to 18% by 2020 will be eventually replaced by the CPRS. In the meantime the target is increased from 13% at 0.5% per year from 2010. Even with a low carbon price, there is enough gas fired generation to meet the Queensland gas fired generation target and so the GEC price would go to zero.

- The assessed demand side management for emissions abatement or otherwise economic responses throughout the NEM is assumed to be included in the NEM demand forecast.

New entry technology

- Carbon capture and storage is not available until 2025/26. The long-term modelling for the Federal Treasury revealed that the threat of (relatively) low cost carbon capture and storage in the face of high carbon prices made problematic the entry of conventional CCGT plant in the medium term as a transitional base load technology. CCGTs would therefore only be commissioned sparingly, and only if prices are high enough to support a relatively rapid recovery of their fixed costs.
- Generation from any nuclear process is not available in the study period.
- Geothermal generation becomes commercially viable in 2017.

Commissioned new entrants and assumed retirements

- The development of an additional four 230 MW gas turbines at the Braemar site in Queensland, two in October 2011 and two in October 2012[19]. These units are treated as variable in timing according to the market scenario.

[19] Note that this power station has not yet reached financial closure.

- The commissioning of a 150 MW cogeneration plant by QAL in September 2012 located in central Queensland.
- ERM Power's plan for four 175 MW gas turbines at Wellington are treated as an expansion option according to market requirement[20].
- The commissioning of a third 25 MW unit at Port Lincoln in South Australia by International Power in January 2010.
- The commissioning of a 621 MW CCGT at Darling Downs by Origin Energy in May 2010, consisting of three 117 MW gas turbines and one 270 MW steam turbine.
- The commissioning of 2 x 275 MW gas turbines at Mortlake in Victoria by Origin Energy in October 2010.
- The commissioning of a 169 MW cogeneration plant by Rio Tinto in May 2010 at its Yarwun alumina refinery located in central Queensland.
- The development of the 400 MW Integrated Drying Gasification Combined Cycle (IDGCC) plant by HRL in the Latrobe Valley from November 2018.
- The retirement of the 2 x 300 MW Munmorah units at the end of March 2014.
- The four units at Swanbank B progressively shut down from June 2010 to April 2012.
- Callide A is in indefinite dry storage but is to be used to test oxy-firing. We have included a single unit in our model from 2010/11 to 2015/16.

Network augmentations

A series of network augmentations in Queensland and North New South Wales are included, consistent with the constraint workbook used for AEMO's ANTS studies. All routine augmentations listed in Table 9.2 of the 2008 SOO are included. Key augmentations assumed include:

- A series of augmentations to increase the central to north Queensland intraregional limit by up to 870 MW by the summer of 2012/13.
- A series of augmentations to gradually increase the Tarong limit over time.
- Removal of most intraregional transmission constraints post 2020, assuming that congestion would be alleviated as and when needed[21].

Any other interconnector upgrades will be co-optimised with generation capacity expansion in the LT Plan.

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20 Note that this power station has not yet reached financial closure.

21 Interconnector limits, and the central to north Queensland limit are still observed though.

Drought effects and hydro optimisation

The drought has had a major impact in different regions, on hydro, pump and thermal units. The following modifications to 'normal' assumptions have been made to replicate these effects.

- Dartmouth has been shutdown until winter 2011 due to drought effects. It comes on-line with a capacity of 130 MW and does not resume normal operation until winter 2012.

- Eildon has restricted energy limits up until winter 2011, at which time it resumes normal operation at 120 MW.

- The long-term annual generation of Hydro Tasmania's hydro generators has been reduced to 9,500 GWh from 2012/13 and thereafter. The annual generation level is assumed to be 8,249 GWh in 2009/10, and increases linearly to 9,309 GWh in 2011/12 to reflect gradual recovery from the drought. The future generation level of 9,500 GWh is less than the historical average of some 10,300 GWh.

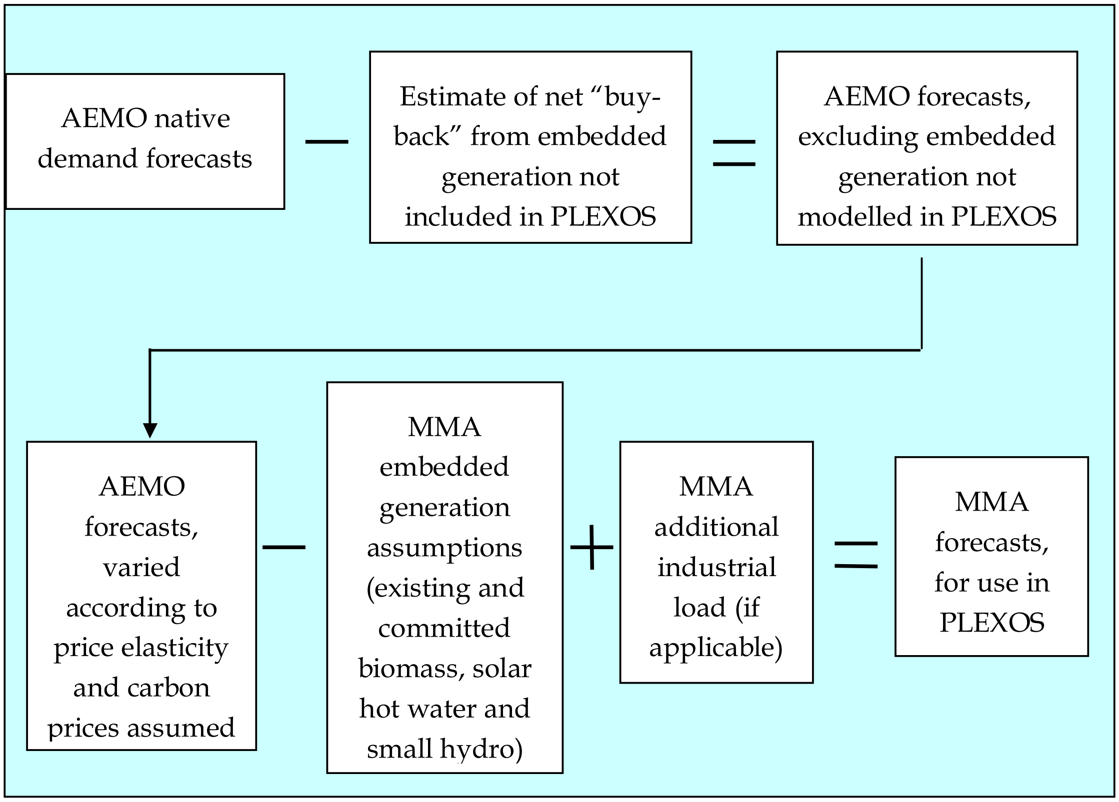
A.4 Demand

A.4.1 Demand forecast and embedded generation

The demand forecast adopted by MMA is based on AEMO's 2009 ESOO. The forecast was applied to the 2005/06 actual half-hourly demand profiles and is shown below for each region from Figure A-2 to Figure A-6 after being adjusted for carbon price. We have used the 2005/06 load shape as it reflects demand response to normal weather conditions and captures the observed demand coincidence between States. The demand and energy forecasts were originally developed by KPMG Econtech.

The flow chart in Figure A-1 presents MMA's methodology for formulating the PLEXOS load forecasts.

Figure A-1 MMA's load forecast methodology



The input demand is assumed to be sent-out demand rather than generator-terminal demand. AEMO's energy projections are expressed on a sent-out basis, but peak demand is expressed on a generator-terminal basis. Therefore, the peak demand projections have been scaled down based on estimates of region average auxiliary losses.

In previous years, the input demand used by PLEXOS was assumed to be generator-terminal demand, and indeed the historical demand trace used to grow the loads is reported on a generator-terminal basis. Because regional auxiliary losses vary from period to period depending on the mix of generation being dispatched, there will be some error arising from using a generator-terminal base load profile for forecasting sent-out load on a half-hourly basis. Moreover, minimum reserve levels specified by AEMO are formulated on a generator-terminal basis rather than a sent-out basis.

However, this forecasting inconsistency was accepted to be minor compared to the error that could arise if assuming generator-terminal load for capacity planning purposes. Some of the potential new technologies such as Integrated Gasification Combined Cycle (IGCC) with or without Carbon Capture and Storage (CCS) have considerably larger auxiliary losses than current generation technologies. If demand were measured on a generator-terminal basis, any capacity expansion plan with these technologies included would essentially be implying lower demand from end-users relative to a plan without these technologies. This implication is clearly erroneous and was the motivating factor for switching to forecasting demand on a sent-out basis.

The introduction of the CPRS adds another complexity to the demand forecasting as it is anticipated that there will be some demand response to the predicted increase in electricity prices. The forecasts published in the 2009 ESOO already include assumptions on how demand may change in response to these higher electricity prices. The 2009 ESOO reports the long-run own price elasticity of electricity by region used to derive this anticipated demand response; these values are summarised in Table A-1 below. This price elasticities represents the percentage change in demand expected for a 1% increase in electricity price.

The magnitude of the expected electricity price increase depends on a number of assumptions, but the key driver is the carbon price that is assumed. AEMO's carbon price assumptions are slightly lower than the assumptions we have used for the CPRS–5% scenario. Consequently, it was necessary to reduce AEMO's forecasts slightly based on an assessment of how our higher carbon prices would influence electricity prices and hence demand response.

With respect to peak demand, we assumed the demand response would be significantly lower and therefore the corresponding change in peak demand was assumed to be only 25% that of the energy reduction.

Table A-1 Assumed price elasticity of demand

State	Price elasticity (%)
NSW	-0.37
VIC	-0.38
QLD	-0.29
SA	-0.25
TAS	-0.23

Source: Table 3.51 NEMMCO SOO 2008, ESIPC Annual Planning Report June 2009 page ix.

Figure A-2 Demand growth forecast sent out for Queensland, Med 50POE

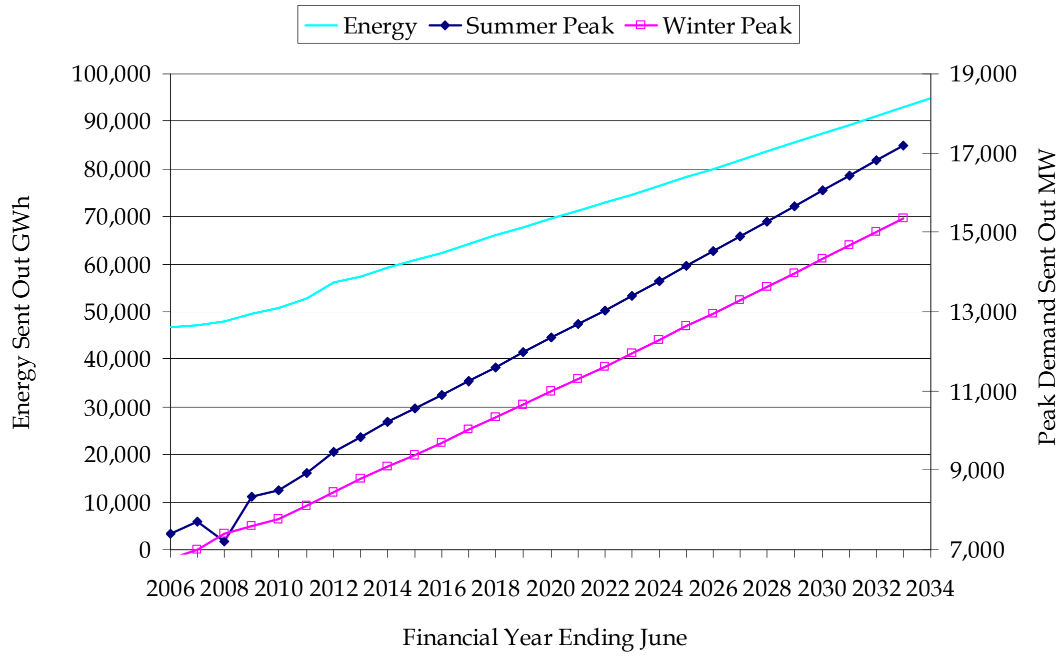


Figure A-3 Demand growth forecast sent out for New South Wales, Med 50POE

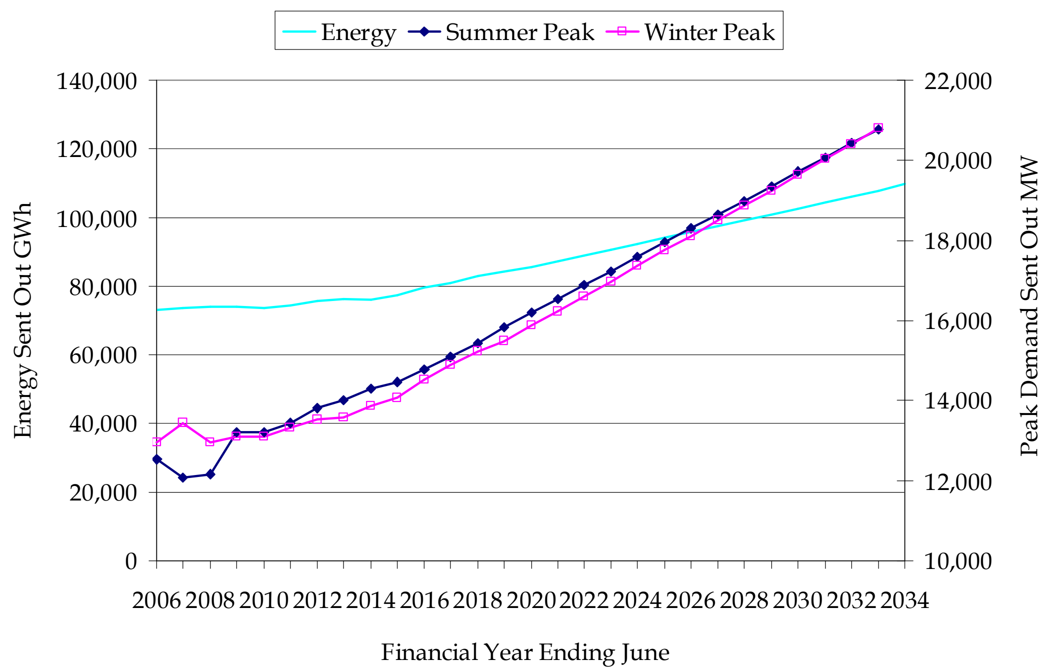


Figure A-4 Demand growth forecast sent out for Victoria, Med 50POE

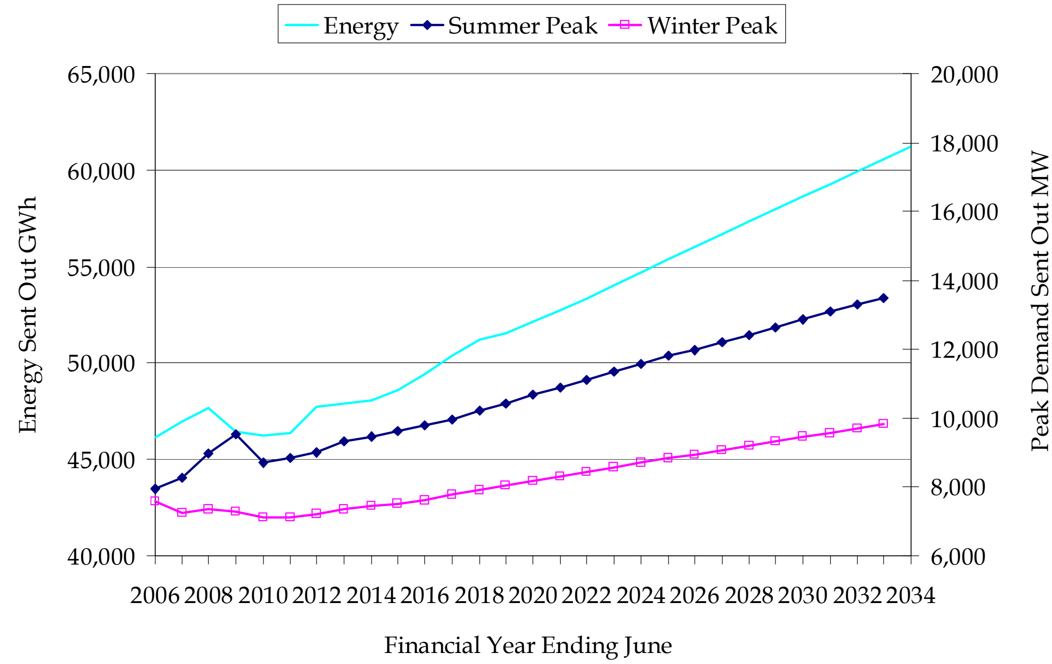


Figure A-5 Demand growth forecast sent out for South Australia, Med 50POE

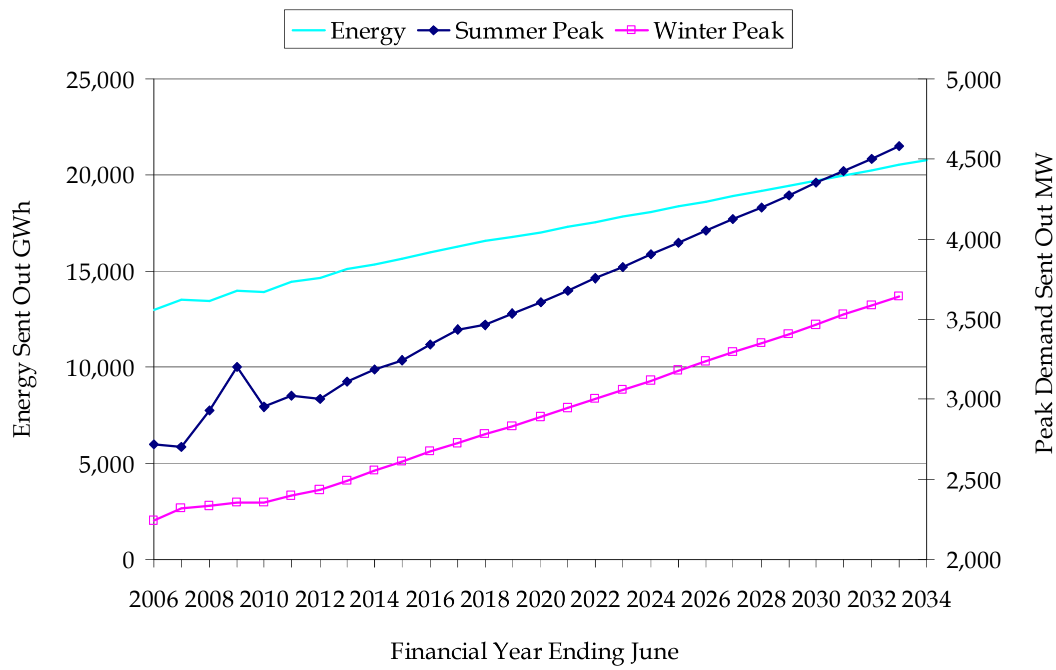
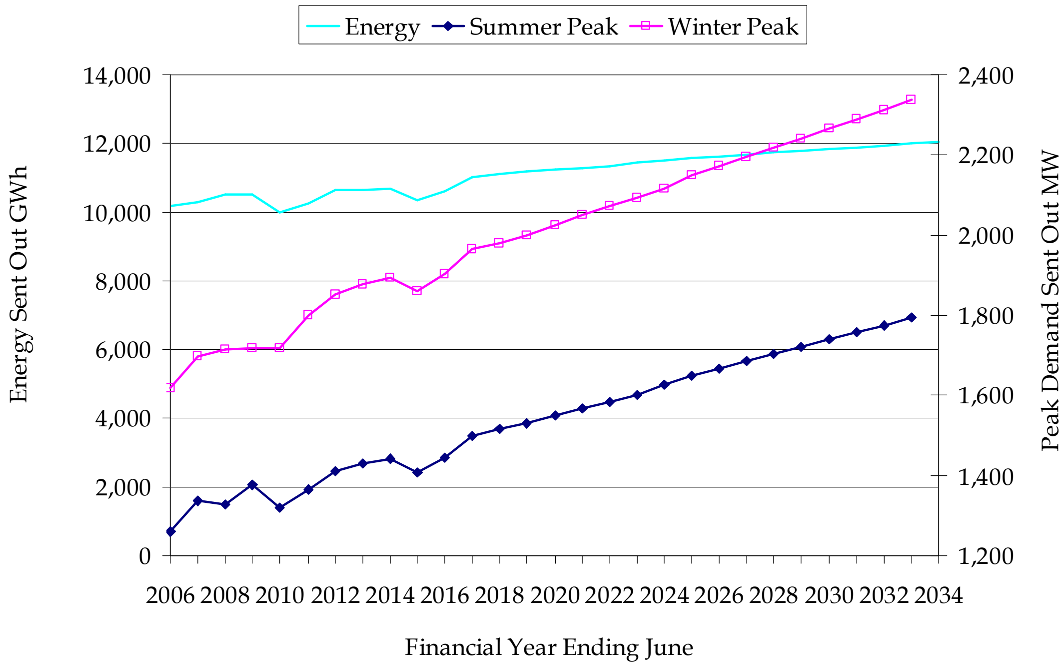


Figure A-6 Demand growth forecast sent out for Tasmania, Med 50POE



A.4.2 Demand side participation

The total amount of demand side participation (DSP) explicitly modelled in MMA's NEM database, as shown in Table A-1 is approximately 113 MW. These figures are based on committed DSP levels reported in AEMO's 2009 ESOO, apportioned to the various price bands using the ratios specified in the 2008 ANTS consultation final report.

Table A-1 DSP bid prices and quantities (MW) in the PLEXOS NEM database

DSP Bid Price ($/MWh)	NSW	QLD	SA	VIC	TAS
500	0	1.6	0	10.77	0
1,000	0	2	6.85	14.68	0
3,000	0	2.8	5.87	21.53	0
5,000	11	3.6	6.85	25.45	0

A.5 Supply

A.5.1 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 types of existing thermal plants are shown in Table A-2. The parameters underlying these costs are presented in detail on a plant by plant basis in Appendix B. We also include the net present value of changes in future capital expenditure that would be driven by fuel consumption for open cut mines that are owned by the generator. This applies to coal costs in Victoria and South Australia.

Table A-2 Indicative average variable costs for existing thermal plant ($June 2009)

Technology	Variable Cost $/MWh	Technology	Variable Cost $/MWh
Brown Coal – Victoria	$7 - $11	Brown Coal – SA	$20 - $26
Gas – Victoria	$43 - $61	Black Coal – NSW	$19 - $22
Gas – SA	$36 - $170	Black Coal - Qld	$8 - $21
Oil – SA	$253 - $314	Gas - Queensland	$25 - $96
Gas Peak – SA	$96 - $172	Oil – Queensland	$240

A.5.2 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%. Capacity, fuel cost and heat rate data at generator are shown in Appendix B.

A.5.3 Planned Maintenance

By specifying the relevant maintenance rates and mean times to repair, PLEXOS will automatically schedule planned maintenance in the PASA and preschedule stage of simulation. Separate to this, the NEM database also has explicit planned maintenance schedules as published by AEMO or the plant operators. Accordingly, CS Energy major planned outages are included in the database[22].

Hydro power stations do not contain planned or forced outage data as they are assumed to be fitted out during times when they are not in operation.

A.5.4 Gas prices

The gas prices are derived from the MMAGas model based on assumption of gradual expansion of the LNG industry commencing mid way through this decade. The prices input into PLEXOS by NEM region are presented in the charts below. Figure A-7 shows gas costs for new entry plant throughout the forecast period. Similarly, Figure A-8 shows the average cost of existing gas contracts, which represents the gas cost for incumbent plant throughout the forecast period.

22 Updates taken from their respective sites and are current as of 5th January 2010.

Figure A-7 Projected New Contract Gas Prices for the Eastern States, $2008 (CPRS-5% carbon price scenario)

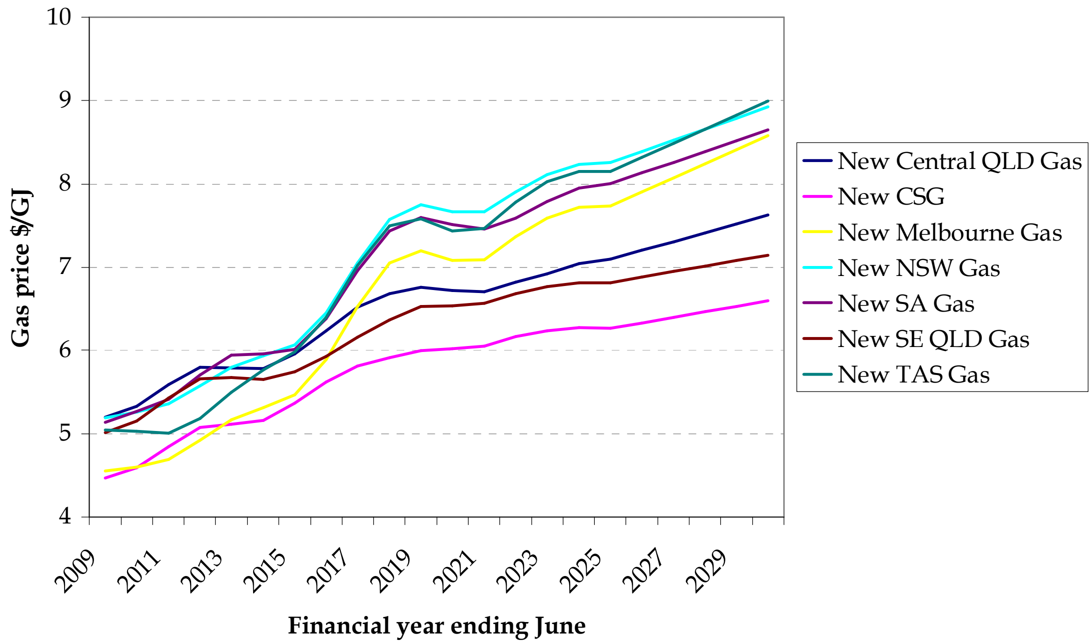
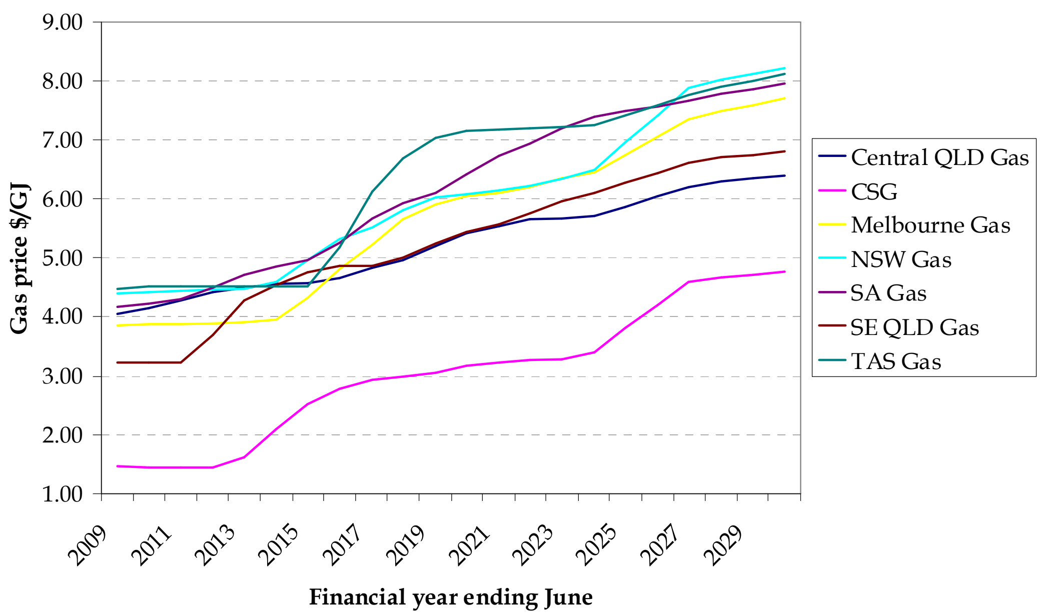


Figure A-8 Projected Average Contract Gas Prices for the Eastern States, $2008 (CPRS-5% carbon price scenario)



A.6 Future NEM developments

A.6.1 Optimal new entry – LT Plan

The long-term capacity expansion model in PLEXOS 5 is called "LT Plan". The purpose of the LT Plan model is to find the optimal combination of generation new builds and retirements and transmission upgrades that minimises the net present value of the total costs of the system over a long-term planning horizon. That is, to simultaneously solve a generation and transmission capacity expansion problem and a dispatch problem from a central planning, long-term perspective. Planning horizons for the LT Plan model are user-defined and are typically expected to be in the range of 20 to 30 years.

LT Plan can be run either separately or integrated with PASA/MT Schedule/ST Schedule in a single simulation. In the latter role, the long-term build/retirement decisions made by LT Plan will be automatically passed to the more detailed simulation phases, providing a seamless solution.

The LT Plan has been used to develop a NEM capacity expansion plan to 2030, accounting for expected carbon prices and the expanded RET. This section summarises the key assumptions and results.

Current computational restrictions limit the planning horizon for a NEM LT Plan to approximately 20 years, using monthly LDC's represented using fourteen load blocks per month.

New generation technologies

There are a number of proposed scheduled generation projects identified in the 2009 ESOO that are included as possible new entrants in the LT Plan. Additionally, generic new entrant technologies are considered including:

- Combined cycle gas turbines (CCGT) with and without carbon capture and storage (CCS).
- Generic open cycle gas turbines.
- Integrated gasification combined cycle generators (IGCC), with and without CCS.
- Integrated drying and gasification combined cycle generators (IDGCC), with and without CCS (for Victoria only).

Supercritical and ultra-supercritical coal units are considered unlikely in the current market environment and are therefore not included in the current LT Plan, although they are present in the database to allow for modelling of alternate market scenarios.

The key input parameters assumed for each of the thermal new entrants considered in the current LT Plan are summarised in Table A-4. The capital costs have been annualised assuming an economic life of 30 years. The pre-tax real equity return was 12%. With respect to modelling capital costs, note that the rapid rate of increase in new entry capital costs experienced from 2005 to 2008 has now collapsed with the global financial crisis, which has seen metal prices fall sharply. This price collapse has been modelled by allowing capital costs to decline back at about CPI-3% which means about constant in nominal terms until they fall back to the long-term trend of CPI-1%.

Existing and new renewable generation

MMA has developed an extensive renewable energy database that contains key costs and operating characteristics for existing, committed, and proposed renewable energy projects in Australia. MMA's renewable energy model (REMMA) uses this database to determine the least cost combination of renewable energy projects to meet the expanded RET in each year. Renewable generators across all states in Australia are eligible to contribute towards the expanded RET scheme.

In the LT Plan it is not plausible to include every potential renewable energy project identified in our database. However, it is important to co-optimise renewable and thermal generation within the expansion plan to ensure that the impact of expanded RET is being adequately represented. We have therefore, used the information in our renewable energy database to develop time-dependent supply cost curves by state for four key renewable sources: wind, geothermal, hydro, and biomass.

By fitting a step-function to these cost-curves, up to five generic renewable projects where identified for each technology by state, with various cost structures. These projects were included as options within the LT Plan and were co-optimised with thermal generation taking account of the:

- Assumed firm contribution to peak load.
- Renewable generation volumes required to meet the expanded ret (ignoring banking).
- Impact of large volumes of renewable generation on the operating regime of thermal generators.

Additionally, penetration into the market of intermittent technologies such as wind is dependent on the ability of the system to absorb such generation. Therefore, the amount of installed wind capacity in each region was capped at 25% of that region's peak demand. If the transmission network to Victoria was upgraded it would be expected that this cap could be exceeded in South Australia.

Retirements

The retirements are co-optimised with new entry, taking account of the avoidable costs assumed and the minimum reserve levels required in each state. Only units considered most significantly impacted by CPRS are included as retirement options in the LT Plan.

These units include:

- Hazelwood, Yallourn, Loy Yang A and Loy Yang B brown coal units in Victoria.
- Playford in South Australia.
- Collinsville and Tarong in Queensland.

Table A-3 summarises the avoidable cost assumptions for the key incumbents at risk from the CPRS.

In addition, the Munmorah black coal units are retired in May and July 2014 as per the 2009 ESOO, and Swanbank B is gradually retired between 2010 and 2012, as per CS Energy's recent announcement.

Table A-3 Avoidable cost assumptions for incumbents

Power station	Avoidable costs ($/kW/yr)
Collinsville	36
Tarong	38
Playford	55
Hazelwood	88
Yallourn	82
Loy Yang A	74
Loy Yang B	59

Network augmentations

Major network augmentations are co-optimised with commitment and retirement of generators in the LT Plan.

Constraints

The LT Plan seeks to minimise the cost of investment and production from a centrally co-ordinated perspective subject to a number of constraints including:

- Constraints on construction resources limiting the rate of IGCC development to one unit per state per year.
- Earliest start years for some technologies (for example CCS is assumed not to be available prior to 2024 in Victoria and 2026 in other states, and geothermal is assumed not to be commercially viable until 2017 at the earliest).
- Requirements to meet the expanded RET
  - wind limited to 25% of peak demand in each region.
- Limits on the maximum number of units built in year, and maximum number of units built total.
- Firm capacity requirements to meet minimum reserve levels for each zone.

For upgrades of GTs to CCGTs, constraints are imposed to ensure that the GTs are retired and replaced by the CCGT alternatives.

Table A-4 Key input assumptions for prospective new entrants (generator terminal assumptions)

	Max capacity (MW)	Capital cost ($/kW)	IDC* factor	CPI factor, medium term	CPI factor, long term	Auxiliary load (%)	Max units built	First year available	VO&M ($/MWh)	MLF	Fixed O&M ($/kW/yr)	Heat rate at max (GJ/MWh)
Victorian new entry options												
Generic-VIC-GT	161	757	1.04	-1.0%	-1.0%	1%	10	2011	2.27	1.009	10.3	10.9
Maryvale Cogen	150	2393	1.04	-1.0%	-1.0%	2%	1	2011	3.22	0.957	27.6	6.9
Latrobe CCGT	373	1078	1.06	-1.0%	-1.0%	2%	0	2011	3.26	0.970	19.8	7.1
Generic-VIC-IDGCC	500	2404	1.10	-1.0%	-1.0%	25%	0	2014	4.08	0.970	39.8	7.3
Generic-VIC-IDGCC-CS	500	2970	1.10	-1.6%	-0.5%	24%	10	2025	4.94	0.961	57.6	8.7
Generic-VIC-Sup	723	2017	1.10	-0.5%	-0.5%	12%	10	2012	5.22	0.970	40.5	9.0
Generic-VIC-USup	723	2420	1.10	-1.0%	-0.5%	12%	10	2012	5.22	0.970	40.5	8.6
Generic-VIC-CCGT	400	1321	1.06	-1.0%	-1.0%	2%	10	2011	3.26	0.970	23.9	7.1
Generic-VIC-CCGT-CS	500	1795	1.06	-1.0%	-0.5%	10%	10	2025	4.18	0.970	39.0	7.2
Mortlake CCGT upgrade	500	1016	1.06	-1.0%	-1.0%	2%	1	2011	3.39	1.008	95.1	7.1
ShawRiver CCGT	500	1118	1.06	-1.0%	-1.0%	2%	3	2011	3.39	1.008	95.1	7.1
New South Wales new entry options												
Buronga GT	140	869	1.03	-1.0%	-1.0%	1%	1	2011	2.28	1.018	10.3	10.9
Parkes GT	136	872	1.04	-1.0%	-1.0%	1%	1	2011	2.32	1.016	10.3	10.9
Pt Kembla	190	1300	1.04	-1.0%	-1.0%	2%	0	2014	3.58	0.995	29.8	6.9
Generic-NSW-GT	200	874	1.04	-1.0%	-1.0%	1%	10	2011	2.22	0.997	10.3	10.7
Generic-NSW-CCGT	400	1321	1.06	-1.0%	-1.0%	2%	10	2011	3.31	0.987	23.9	7.1
Generic-NSW-CCGT-CS	500	1795	1.05	-1.0%	-0.5%	10%	10	2025	4.16	0.961	39.0	7.1
NSW-CCGT-MM	350	1199	1.06	-1.0%	-1.0%	2%	4	2011	3.31	0.984	18.8	7.1

	Max capacity (MW)	Capital cost ($/kW)	IDC* factor	CPI factor, medium term	CPI factor, long term	Auxiliary load (%)	Max units built	First year available	VO&M ($/MWh)	MLF	Fixed O&M ($/kW/yr)	Heat rate at max (GJ/MWh)
Tomago GT	250	694	1.04	-1.0%	-1.0%	1%	2	2011	2.16	0.980	10.3	10.5
Tomago CCGT upgrade	750	996	1.06	-1.0%	-1.0%	2%	1	2011	3.24	0.980	18.8	7.1
Bamarang GT	330	676	1.04	-1.0%	-1.0%	1%	1	2011	2.16	0.980	10.3	10.5
Bamarang CCGT upgrade	450	1055	1.06	-1.0%	-1.0%	2%	1	2011	3.24	0.980	18.8	7.1
Marulan_D GT	330	676	1.04	-1.0%	-1.0%	1%	1	2011	2.21	0.981	10.3	10.5
Marulan_D CCGT upgrade	420	1063	1.06	-1.0%	-1.0%	2%	1	2011	3.32	0.981	18.8	7.1
Mt Piper Ext 1	1000	889	1.03	-1.0%	-1.0%	6%	0	2010	2.39	0.961	27.6	9.1
Mt Piper Ext 2	1000	889	1.03	-1.0%	-1.0%	6%	0	2011	2.39	0.961	27.6	9.1
Wellington GT	175	853	1.04	-1.0%	-1.0%	1%	5	2007	2.17	0.953	10.3	10.9
Generic-NSW-IGCC	710	2397	1.07	-1.6%	-1.0%	22%	0	2014	1.98	0.961	37.1	7.1
Generic-NSW-IGCC-CS	630	3181	1.10	-1.6%	-1.0%	25%	10	2025	2.91	0.987	40.6	8.6
Generic-NSW-Sup	750	2010	1.10	-0.5%	-0.5%	8%	0	2012	3.12	0.980	29.9	8.8
Generic-NSW-USup	750	2412	1.10	-0.5%	-0.5%	8%	0	2012	3.18	0.987	37.3	8.0
South Australian new entry options												
Arckaringa	280	2404	1.10	-1.0%	-1.0%	25%	3	2014	4.05	0.964	39.8	7.3
Generic-SA-GT	130	909	1.04	-1.0%	-1.0%	1%	10	2011	5.60	1.001	32.0	10.9
Generic-SA-CCGT	242	1393	1.06	-1.0%	-1.0%	2%	0	2011	3.36	1.001	22.1	7.1
Hallett 11_12	130	472	1.03	-1.0%	-1.0%	1%	3	2010	3.72	1.001	32.0	10.9
Mintaro2	40	577	1.03	-1.0%	-1.0%	1%	0	2010	3.60	0.965	33.9	15.9
PPCCGT2	300	1105	1.06	-1.0%	-1.0%	2%	1	2010	3.36	1.001	22.1	7.1
Large-SA-CCGT	400	1321	1.06	-1.0%	-1.0%	2%	0	2011	3.24	0.980	23.9	7.1

	Max capacity (MW)	Capital cost ($/kW)	IDC* factor	CPI factor, medium term	CPI factor, long term	Auxiliary load (%)	Max units built	First year available	VO&M ($/MWh)	MLF	Fixed O&M ($/kW/yr)	Heat rate at max (GJ/MWh)
Generic-SA-CCGT-CS	500	1795	1.05	-1.0%	-0.5%	10%	10	2025	4.31	1.001	39.0	7.2
Queensland new entry options												
Generic-QLDNth-GT	130	909	1.04	-1.0%	-1.0%	1%	10	2011	5.60	1.000	32.4	10.9
Generic-QLDNth-CCGT	170	1447	1.06	-1.0%	-1.0%	2%	10	2011	3.36	1.000	19.5	7.8
Generic-QLDNth-CCGT-CS	500	1795	1.06	-1.0%	-0.5%	10%	10	2025	4.31	1.000	39.0	7.2
Large-QLDNth-CCGT	400	1321	1.06	-1.0%	-1.0%	2%	0	2011	3.29	1.000	23.9	7.1
Generic-QLDSth-GT	146	765	1.04	-1.0%	-1.0%	1%	10	2008	3.81	1.068	31.9	10.9
Generic-QLDSth-CCGT	393	1324	1.06	-1.0%	-1.0%	2%	10	2011	3.64	1.068	19.3	7.1
Generic-QLDSth-CCGT-CS	500	993	1.06	-1.0%	-0.5%	10%	10	2025	4.54	1.068	39.0	7.2
SWAN_F	400	1069	1.06	-1.0%	-1.0%	2%	1	2011	3.31	0.978	23.9	7.1
Generic-QLDTar-BLCL	450	2057	1.10	-1.0%	-1.0%	6%	0	2017	3.35	0.995	32.8	9.4
Spring Gully	500	1136	1.06	-1.0%	-1.0%	3%	10	2011	3.37	0.968	19.3	7.0
Generic-QLDTar-CCGT	500	1795	1.06	-1.0%	-0.5%	10%	10	2025	4.21	0.968	39.0	7.2
MPP_BLCL	420	1739	1.12	-1.0%	-1.0%	6%	0	2013	2.23	0.995	27.5	9.4
TNPS2	441	1841	1.12	-1.0%	-1.0%	6%	0	2013	1.03	1.000	31.5	9.4
Braemar exp	173	348	1.04	-1.0%	-1.0%	1%	10	2008	3.55	0.968	31.9	10.9
Generic-QLDTar-IGCC	710	2397	1.07	-1.6%	-1.0%	22%	0	2014	2.05	1.000	37.1	7.1
Generic-QLDTar-IGCC-CS	630	3181	1.07	-1.6%	-1.0%	25%	10	2025	2.89	0.968	40.6	8.6
Generic-QLDTar-Sup	750	2010	1.10	-0.5%	-0.5%	8%	0	2012	3.23	1.000	29.9	8.8
Generic-QLDTar-USup	750	2412	1.10	-0.5%	-0.5%	8%	0	2012	3.16	0.968	37.3	8.0
Generic-QLDCen-CCGT	388	1374	1.06	-1.0%	-1.0%	2%	1	2011	3.25	0.971	19.5	7.4

	Max capacity (MW)	Capital cost ($/kW)	IDC* factor	CPI factor, medium term	CPI factor, long term	Auxiliary load (%)	Max units built	First year available	VO&M ($/MWh)	MLF	Fixed O&M ($/kW/yr)	Heat rate at max (GJ/MWh)
Generic-QLDCen-BLCL	450	2057	1.10	-1.0%	-1.0%	6%	0	2012	3.89	0.971	32.8	9.4
Generic-QLDCen-Sup	750	2010	1.10	-0.5%	-0.5%	8%	0	2012	3.23	1.002	29.9	8.8
Generic-QLDCen-USup	750	2412	1.10	-0.5%	-0.5%	8%	0	2012	3.23	1.002	37.3	8.0
Generic-QLDCen-IGCC	710	2397	1.10	-1.6%	-1.0%	22%	10	2014	2.05	1.002	37.1	7.1
Generic-QLDCen-IGCC-CS	630	3181	1.10	-1.6%	-1.0%	25%	10	2025	2.96	1.002	40.6	8.6
Tasmanian new entry options												
Generic-Tas-GT	161	354	1.04	-1.0%	-1.0%	1%	10	2011	5.67	1.009	31.7	10.9
Generic-Tas-CCGT	200	1422	1.06	-1.0%	-1.0%	2%	3	2012	3.36	0.999	16.8	7.8

*IDC = Interest during construction.

A.6.2 New entry

MMA formulates future NEM development ensuring that the reserve requirements are met in each region at least cost. The minimum reserve levels assumed for each state are based on values specified in the 2009 ESOO and are summarised in Table A-5. The minimum reserve level for VIC and SA combined is 615 MW of which -50 MW has been allocated to SA by AEMO in an attempt to minimise the local reserve requirement in SA. This means that Victoria must carry 665 MW when South Australia is fully relying on Victoria. Post Kogan Creek the size of the largest unit in QLD increased by 300 MW, however this only translates to an 80 MW increase in minimum reserve levels for the region.

Table A-5 Minimum reserve levels assumed for each state

Region	Qld	NSQ	Vic	SA	Tas
Reserve Level	560 MW	-1430 MW	665 MW	-50 MW	144 MW

A.7 Transmission losses

A.7.1 Inter-regional losses

Inter-regional losses are modelled in PLEXOS directly through the use of the Loss Factor equations which are periodically published by AEMO. The latest set produce by AEMO[23] is incorporated in the current database as follows:

Loss factor equation of NSW1-QLD1 (South Pine 275 referred to Sydney West 330)

$= 0.9751 + 1.8839E\text{-}04{*}NQ_t - 7.9144E\text{-}07{*}N_d + 1.1623E\text{-}05{*}Q_d$

Loss factor equation of VIC1-NSW1 (Sydney West 330 referred to Thomastown 66)

$= 0.9649 + 1.7257E\text{-}04{*}VN_t - 1.4631E\text{-}05{*}V_d + 5.7202E\text{-}06{*}N_d + 1.4938E\text{-}05{*}S_d$

Loss factor equation of V-SA (Torrens Island 66 referred to Thomastown 66)

$= 1.0235 + 3.5816E\text{-}04{*}VSA_t - 4.6640E\text{-}06{*}V_d + 5.9808E\text{-}06{*}S_d$

Loss factor equation of Terranora (South Pine 275 referred to Sydney West 330)

$= 0.0726{*}Flow_t + 7.9652\text{-}04{*}(Flow_t)^2$

Loss factor equation of Murraylink (Torrens Island 66 referred to Thomastown 66)

23 List of Regional Boundaries and Marginal Loss Factors for the 2009/10 Financial Year..

$= 0.0596*Flow_t + 1.4770E\text{-}03*(Flow_t)^2$

where,

Q_d = Queensland demand

V_d = Victorian demand

N_d = New South Wales demand

S_d = South Australian demand

NQ_t = transfer from New South Wales to Queensland

VN_t = transfer from Victoria to New South Wales

VSA_t = transfer from Victoria to South Australia

$Flow_t$ = flow through the relevant line

The Basslink loss factor equations were optimised to match flows against losses (in both transfer directions) in a separate MMA analysis. The parameters of the quadratic fit are used in PLEXOS and are presented in Table A-6. MMA treats Basslink's losses in this way in order to model all losses between the Georgetown reference node and the Thomastown reference node. AEMO's published equations for Basslink losses are not sufficient to input into PLEXOS as they are only applicable between Georgetown and the Loy Yang node, which is Basslink's connection point to the mainland.

Table A-6 PLEXOS loss parameters for Basslink flows

PLEXOS Property	Value
Loss Base (Constant)	0.92985000
Loss Incr (Linear term)	0.03663000
Loss Incr2 (Quadratic term)	0.00007400
Loss Base Back (Constant)	0.02589937
Loss Incr Back (Linear term)	-0.03552415
Loss Incr2 Back (Quadratic term)	0.00010341

A.7.2 Apportioning inter-regional losses to regions

PLEXOS emulates AEMO's dispatch engine (NEMDE) in that it allocates the inter-regional losses arising from the preceding loss factor equations to the two regions associated with the relevant interconnector. The apportioning factors used are those published by AEMO in its periodic publication on Marginal Loss Factors[24]. The latest apportioning factors are presented in Table A-7.

Table A-7 Interconnector loss apportioning factors

Interconnector	Apportioning factor	Region applied to
NSW1-QLD1	0.57	NSW
Terranora	0.65	NSW
VIC1-NSW1	0.61	NSW
V-SA	0.70	Vic
Murraylink	0.72	Vic

A.7.3 Intra-regional losses

Intra-regional loss factors refer each generating unit to the regional reference node and are entered into PLEXOS directly. These factors are also sourced from AEMO's periodic publication on Marginal Loss Factors[25].

A.8 Hydro modelling

Small hydro systems such as those owned by Southern Hydro are modelled using annual energy limits. Dartmouth and Eildon have energy constraints restraining production due to the effects of drought.

For larger hydro systems such as the Snowy hydro generation system (excluding Blowering), a more complex cascading network has been set up in the database to emulate physical water flows and levels in the storages. This follows a similar modelling structure to AEMO. Details of AEMO's methodology can be found in the 2008 ANTS Consultation: Final Report.

The inflow data in the 2008 ANTS was provided for the Eucumbene storage rather than for Tumut and Murray separately. Accordingly, we have now included this storage was included in the Snowy representation. Furthermore, in order to allow PLEXOS to appropriately allocate hydro from this large storage to Tumut and Murray, volumes in storage are now measured in cumec days (CMD) rather than GWh, and efficiencies (MW/cumec) are input for each of the generators on the river chain. This required changing the storage model used in the database from potential energy to metric volume.

The ANTS storage volumes are expressed in ML and can be simply converted to CMD given that 1 CMD is equivalent to 86.4 ML. Similarly, we have converted storage inflows were converted from GL to cumecs. The *efficiency incr* (MW/cumec) property

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24 *Ibid.*

25 *Ibid.*

values for generators drawing water from storage are summarised in Table A-8 and have been calculated using the following formula:

MW/cumec = head [in meters] * efficiency * 9.80665 /1000

where an efficiency of 83% is assumed for all generators.

All hydro systems within the same database need to use the same units. Therefore, all storages are measured in CMD and inflows are measured in cumecs. One CMD is equivalent to 24 cumecs. For most of the storages outside the Snowy hydro scheme, rather than convert inflows from MW to cumecs, we have converted the storage initial and end volumes assuming that 1 CMD = 24 MWh. This ensures internal consistency when calculating hydro energy potential[26].

Table A-8 Calculation of MW/cumec efficiency factors for hydro generators attached to storages

Station	head [m]	efficiency	MW/cumec
Kareeya	420	0.83	3.42
Murray Inflow	855	0.83	6.96
Murray1	517	0.83	4.21
Murray2	285	0.83	2.32
Tumut Inflow	811	0.83	1.83
Tumut1	330	0.83	2.69
Tumut2	275	0.83	2.24
Tumut3	160	0.83	1.30

The storages in PLEXOS cycle back to their initial volumes at the end of every year which means all inflows must either be released from the system via generation or waterways. Inflow inputs are based on historical monthly inflows. Since storages are assumed to recycle within a year, the inflows (less spill) determine the generation levels on an annual basis[27].

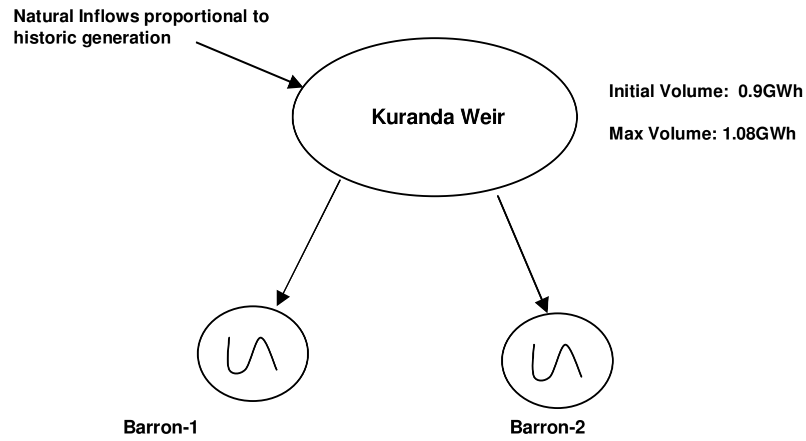
A.8.1 Queensland hydro

The Barron Gorge, Kareeya and Wivenhoe hydro systems in Queensland are modelled in PLEXOS using storage objects. Storage inflows assumed are consistent with the 2009 NTS assumptions. Visual representations and properties of the hydro systems modelled in PLEXOS are presented below from Figure A-9 to Figure A-11.

[26] This is an interim measure. In future versions of the database, we anticipate converting all inflows from MW to cumecs.

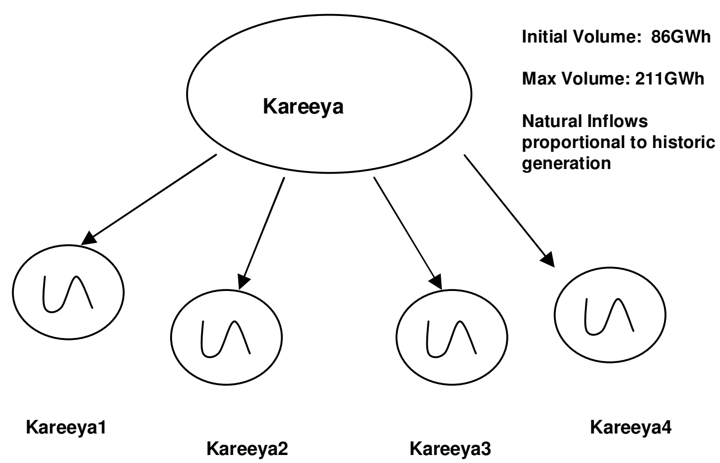
[27] Distribution of generation within the year is based on the water value (an endogenous variable) which accounts for the opportunity cost of thermal resources displaced by the hydro generation in future periods.

Figure A-9 Representation of Barron Gorge hydro system



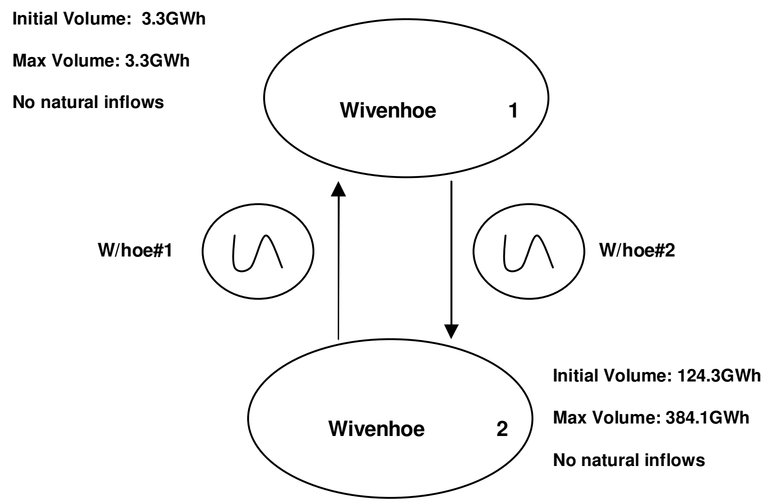
NOTE: In PLEXOS, the storage volumes for this storage are increased by a factor of 41.6667 (1/0.0024) as an alternative to adjusting the value of the inflows to reflect change of units from MW and GWh to cumecs and CMD

Figure A-10 Representation of Kareeya hydro system



NOTE: In PLEXOS, the storage volumes for this system are increased by a factor of 41.6667 (1/0.024) as an alternative to adjusting the value of the inflows to reflect change of units from MW and GWh to cumecs and CMD

Figure A-11 Representation of Wivenhoe pump storage system



NOTE: In PLEXOS, the storage volumes for this system are increased by a factor of 41.6667 (1/0.024) as an alternative to adjusting the value of the inflows to reflect change of units from MW and GWh to cumecs and CMD

A.8.2 Snowy Mountains Scheme

There are seven power stations in the Snowy Mountains Scheme: Guthega, Blowering, Tumut 1, Tumut 2, Tumut 3, Murray 1 and Murray 2. The combined average annual production from the scheme is 4,500 GWh[28], excluding additional generation obtained from pumping. Lake Eucumbene is the main storage for the scheme, with inflows from the storage feeding both the Tumut and Murray hydro systems. There are also three pump storage units at Tumut 3, allowing water to be pumped back up to the Talbingo dam if economic to do so. In PLEXOS we have assumed a pump efficiency of 70% for these three units, meaning that for every MW of pump load, 0.7 MW of potential energy is returned to the Talbingo dam.

The Guthega power station is modelled as a separate hydro system with natural inflows equivalent to the inflows assumed in the 2009 NTS.

In PLEXOS, the Blowering power station is not connected to any storage, but instead monthly energy constraints were used to limit its generation potential. These constraints are summarised in Table A-9 below.

Table A-9 Monthly energy constraints for Blowering (GWh)

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0	0	0	0	0	0	0	6	25	31	34

Source: NEMMCO (2009) NTS Consultation Final Report, Table 18, pg62

28 http://www.snowyhydro.com.au/levelThree.asp?pageID=244&parentID=66&grandParentID=4. last cited 08/01/2010.

Visual representations and properties of the Snowy Mountains hydro storage systems modelled in PLEXOS are presented below from Figure A-12 to Figure A-14.

Figure A-12 Representation of Guthega hydro system

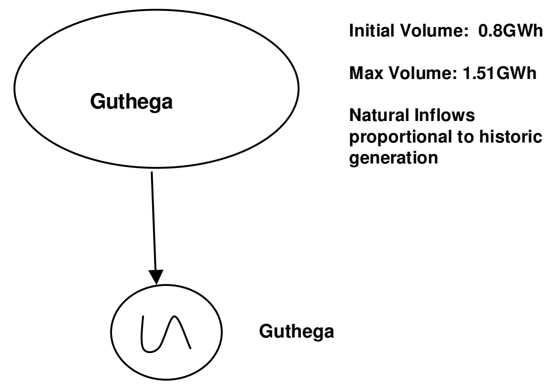


Figure A-13 Representation of Murray hydro system

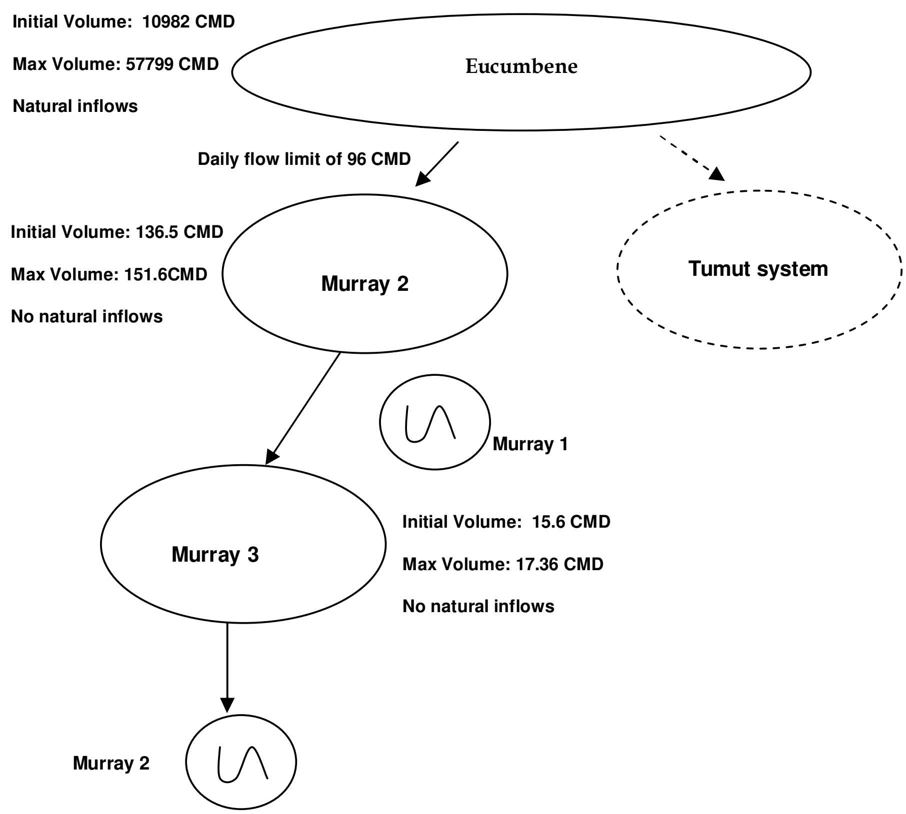
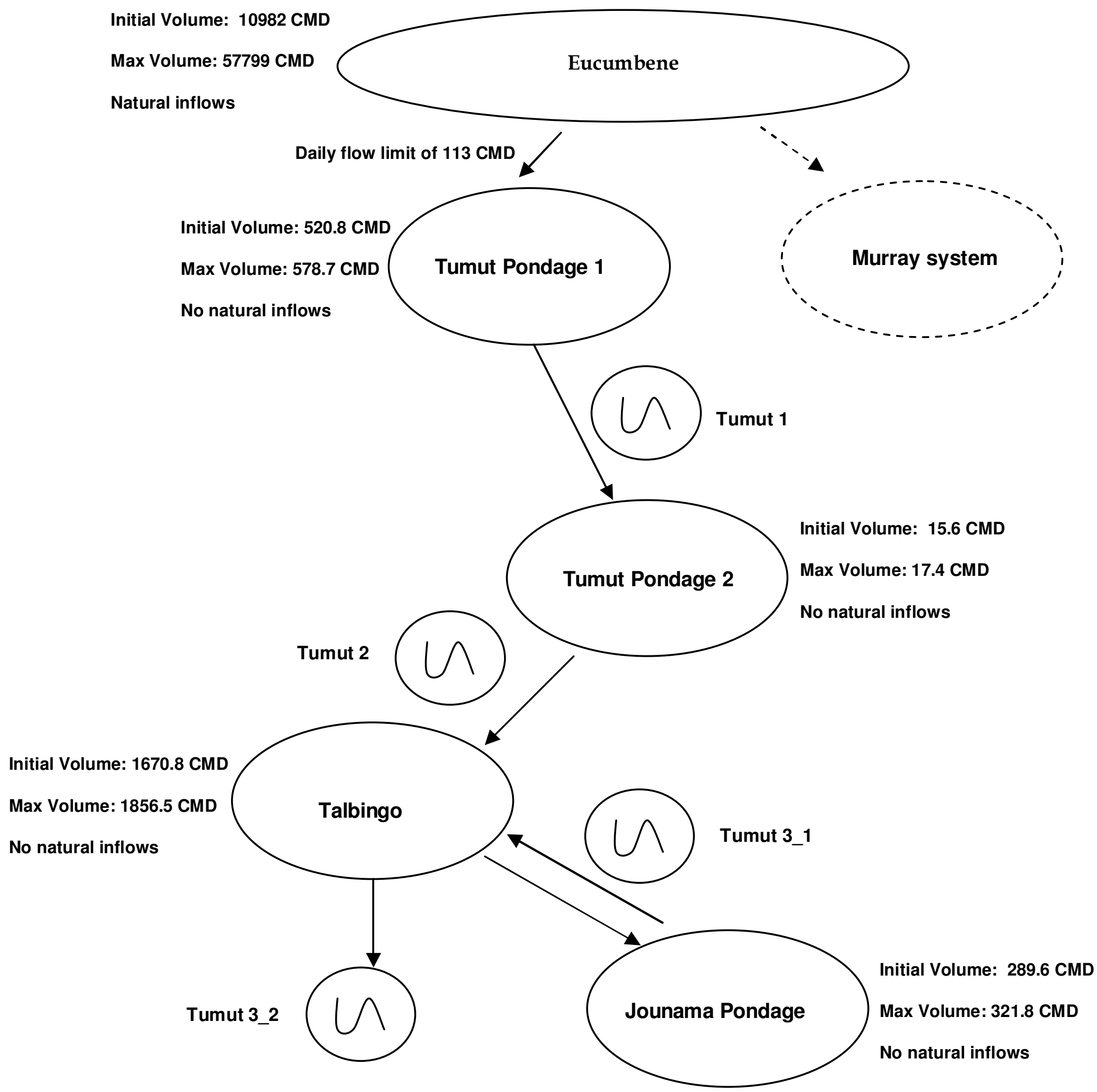


Figure A-14 Representation of Tumut hydro and pump storage systems



NOTE: In PLEXOS, the storage volumes for this system are increased by a factor of 41.6667 (1/0.024) as an alternative to adjusting the value of the inflows to reflect change of units from MW and GWh to cumecs and CMD

A.8.3 Southern Hydro

Southern Hydro operates Dartmouth, Eildon, West Kiewa, and McKay Creek hydro power stations, with Bogong currently under construction. In PLEXOS, these power stations are modelled using monthly energy constraints, based on average output from 1999 to 2007. The last two years have not been used in calculating these long-term averages due to the drought impact. Bogong is assumed to have an annual average output of 94 GWh.

Table A-10 Monthly energy constraints for Blowering (GWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Dartmouth	24.9	21.0	10.8	4.3	3.3	6.0	11.3	28.7	27.9	35.3	35.2	29.5
Eildon	20.0	16.0	16.3	10.3	1.8	0.4	0.6	2.1	3.7	5.9	7.0	13.6
McKay	4.9	6.1	2.0	3.6	4.5	7.7	9.9	6.2	12.0	12.6	8.6	6.0
W. Kiewa	5.7	5.5	4.0	4.6	6.7	13.2	15.0	16.9	24.9	21.6	14.0	9.3

In the short term, the winter ratings and annual output for both Dartmouth and Eildon and have been reduced to reflect the drought impact. These reductions are progressively lifted and by summer 2012/13 Southern Hydro is expected to be back to full capacity. Dartmouth does not expect to commence operation again until winter 2011.

A.8.4 Hydro Tasmania

The Tasmanian hydro system is represented using three water storages which can be identified in the database as TAS Long-Term, TAS Medium-Term and TAS Run of River. The individual power stations associated with each of the three storages are presented below in Table A-11.

Table A-11 Tasmanian hydro power station maximum capacities and allocation to the three storages

Storage	Generator	Max Capacity (MW)
Long Term	Gordon	432
	Poatina110	100
	Poatina220	200
Medium Term	Bastyan	80
	Catagunya	48
	Fisher	43
	JohnButters	144
	LakeEcho	32
	Liapootah	84
	Mackintosh	80
	Tarraleah	90
	Tungatinah	125
	Wayatinah	38
Run of River	Cethana	85
	DevilsGate	60
	Meadowbank	40
	Reece1	116
	Reece2	116
	Lemonthyme	51
	Trevallyn	95
	Tribute	83
	Wilmot	31

Tasmanian storage inflows are historical monthly inflows obtained from the 2009 NTS that have been adjusted in the short to medium term to reflect the current drought conditions. For the 2009 financial year, Tasmanian storage inflows are at 73% of the long-term average. This percentage is increased linearly until 2013, by which time we assume that the Tasmanian storages have fully recovered from the current drought conditions. Long-term average inflows are assumed to be equivalent to 9,500 GWh per annum, consistent with the ANTS, although it is noted that Hydro Tasmania has indicated that the future long-term average may be lower than this.

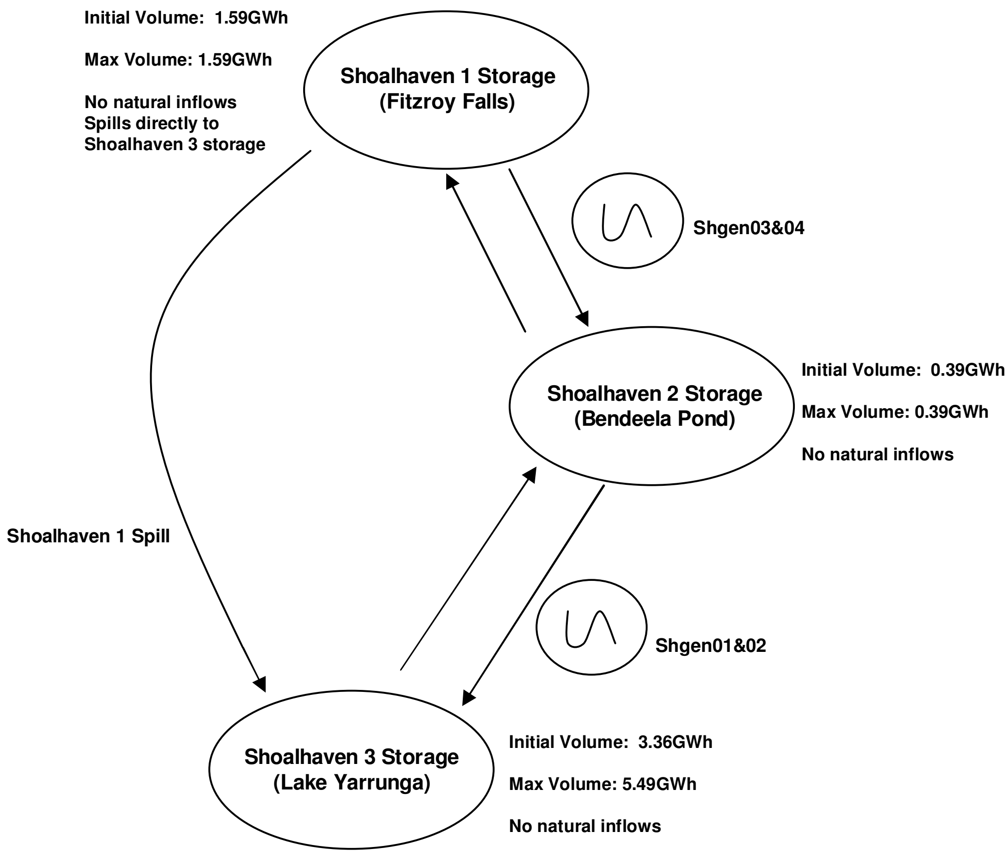
As with the other hydro systems, having specified monthly inflows obtained from the 2009 NTS, PLEXOS will optimise the use of the water within the year taking account of storage upper and lower bounds.

A.8.5 Other hydro systems

Other hydro systems included in the market simulations include the Shoalhaven pump storage system and the Hume hydro system.

The Shoalhaven pump storage system is effectively a closed-system with little/no storage inflows. The representation of this system in PLEXOS is shown in Figure A-15. For the pumping units, a pump efficiency of 70% is assumed.

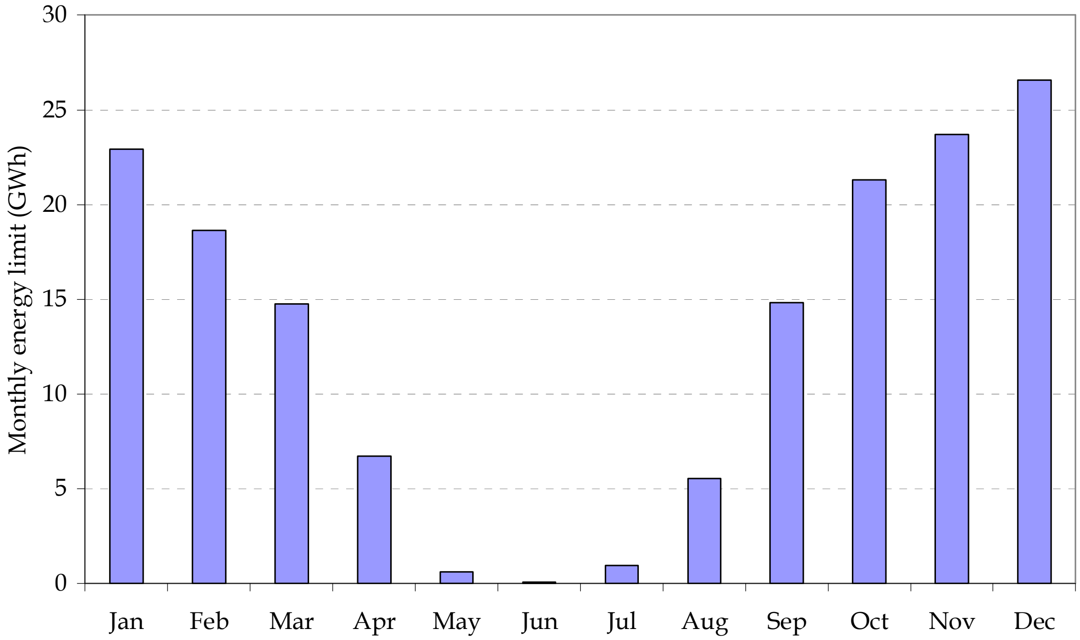
Figure A-15 Representation of Shoalhaven pump storage system



NOTE: In PLEXOS, the storage volumes for this system are increased by a factor of 41.6667 (1/0.024) as an alternative to adjusting the value of the inflows to reflect change of units from MW and GWh to cumecs and CMD

The Hume Dam on the Murray River provides storage for the Hume Power Station which can generate into either NSW or VIC. The NEM database is set up to allow PLEXOS to choose whether to dispatch into NSW or VIC by limiting the total generation from the Hume VIC and Hume NSW generators to 58 MW in all periods (*Hume generation constraint*). In addition, monthly generation limits are imposed on the combined output of the two generators. These limits, shown in Figure A-16, are based on historical generation levels. Between May and July the units are effectively unavailable, consistent with the 2009 ESOO assumptions. Moreover, for capacity planning purposes, it is assumed that all generation is dispatched into Victoria over the summer peak demand period. Hence, the firm capacity for Hume NSW is set to zero.

Figure A-16 Hume Power Station monthly energy limit



A.9 Modelling other renewable energy technologies

Non-hydro renewable generation modelled in the PLEXOS NEM database includes wind, geothermal, biomass/bagasse, new hydro and solar thermal. The availability of this renewable generation is represented through a combination of profiles, stochastic variables, forced outage rates and maximum capacity factors. This section summarises the key assumptions for each renewable generation type. Table A-13 provides a summary of the range of new entry cost and financial assumptions contained within MMA's database of renewable projects.

A.9.1 Wind

Wind farms are modelled as multiple units, each with a maximum capacity of 1 MW. Up to six generic locations are assumed in each state to represent some diversity in availability – the six in NSW are based on the renewable energy zones. With high wind penetration expected in the future, modelling only six generic locations models the fact that there is high correlation between wind farms situated in similar locations, as observed already in South Australia. Typically, each wind farm operates at an average capacity factor of between 25% and 45%, with intermittency represented through the use of stochastic wind profiles. Wind profiles are randomly developed within PLEXOS assuming a log-normal distribution and high autocorrelation from one period to the next, using parameters determined from historical wind profiles.

In modelling the NSW wind farms, historical profiles from two existing wind farms were used. The profiles had a correlation coefficient of 76%, which is remarkably high, and reinforces the statement in the preceding paragraph that the output of wind farms in similar locations is highly correlated (the wind farms are approximately 50km apart). However, MMA has also found that the correlation decreases as the distance between wind farms increases. Thus, in Victoria the correlation coefficient between two wind farms that are 200km apart is only 40%.

For capacity planning purposes, the firm capacity of the wind farms at times of 10% POE peak demand is assumed to be 8% or lower, as shown in Table A-12.

Table A-12 Firm capacity assumed for wind farms, by state

	QLD	NSW	VIC	SA	TAS
Firm capacity	0%	5%	8%	3%	0%

Source: AEMO (2009) Statement of Opportunities, Table B.44, pg B-27.

A.9.2 Geothermal

Geothermal generation is modelled in increments of 50 MW with an average availability of 85%. The key assumptions influencing this availability were:

- Maintenance rate of 4.2%.
- Forced outage rate of 8%.
- Summer derating of 3.5 mw.
- Commercial viability from 2017 onwards.

For capacity planning purposes, geothermal generation is assumed to be 100% firm.

A.9.3 Biomass, bagasse, wood waste

In PLEXOS, biomass encompasses wet waste, wheat/ethanol, agricultural waste, bagasse, black liquor, landfill gas, municipal solid waste, sewage, and wood/wood waste. MMA maintains a renewable database of prospective renewable projects in Australia, detailing costs and generation potential for a large number of these types of projects. For PLEXOS modelling in each state, technologies with similar cost structures have been grouped together to form up to 5 “biomass” generation projects.

Not surprisingly, the expected capacity factor varies greatly between each generation project depending on the type of projects including within the group. Project specific monthly capacity factors are therefore input for each generation project modelled. To represent the possibility of non-firm fuel supply, biomass projects are assumed to be 80% firm for capacity planning purposes.

A.9.4 New hydro

In Queensland, New South Wales and Tasmania, the main new hydro development eligible for renewable energy certificates are likely to be upgrades to the existing hydro schemes. Therefore, in these states, the new hydro projects are modelled as energy constrained units, with annual maximum capacity factors. In Victoria, the new hydro opportunities identified in our renewable database are smaller run-of-river schemes with little or no ability to store the water. Consequently, the renewable hydro projects in Victoria have been modelled with high forced outage rates to reflect a degree of randomness in availability. For capacity planning purposes, this run-of-river hydro is assumed to be 40% firm.

A.9.5 Solar thermal

Photovoltaic and solar thermal generation are modelled as multiple units of 1 MW, using generic profiles to represent the solar radiation potential throughout a day and across a year. Figure A-17 shows the generic profile applied for December, assuming no storage potential. In winter, the estimated profile is 80% lower than in this figure.

For capacity planning purposes, PV/solar thermal is assumed to be 100% firm.

Figure A-17 Daily PV/solar profile for December

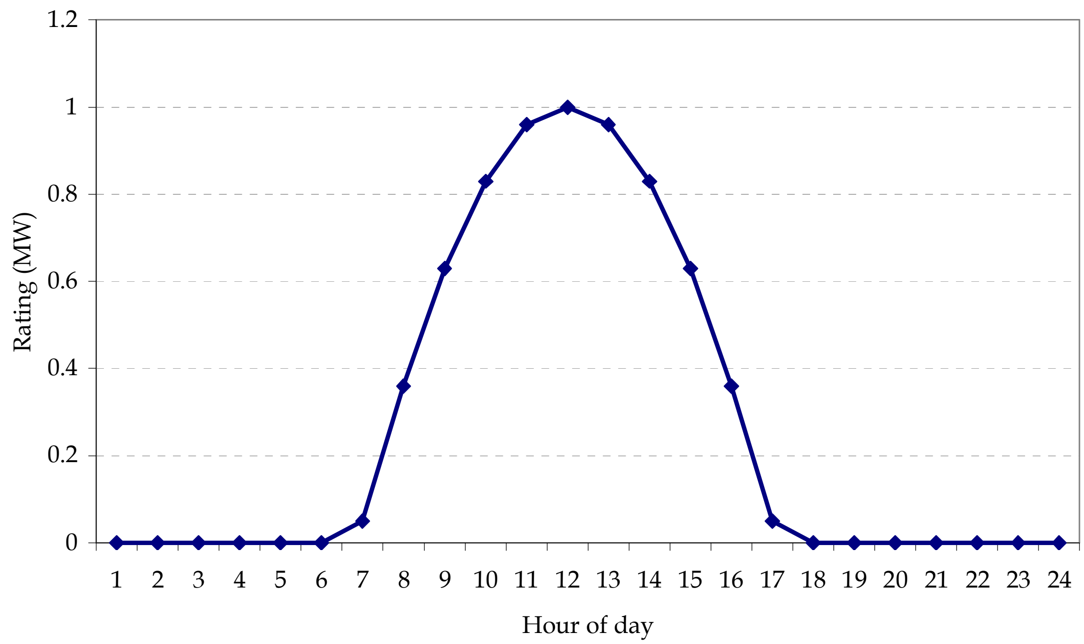


Table A-13 New entry cost and financial assumptions for renewable generators for 2009/10 ($ June 2009)

State	Type of Plant	Capital Cost (sent-out)	Available Capacity Factor	VO&M & Fuel cost	Weighted Cost of Capital	Interest Rate	Debt Level	LRMC	Capital cost reduction
		$/kW sent out		$/MWh	% real	% nominal	%	$/MWh	% per annum
SA	Wind	$2689 - $4217	26% - 36%	$7.3 - $7.3	11.00%	9%	60%	$118 - $238	0.4%
	Biomass	$3159 - $6664	57% - 80%	$20.9 - $50.2	12.00%	9%	60%	$118 - $178	0.3%
	Hydro	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Geothermal	$4643 - $6598	85% - 85%	$23 - $23	11.00%	9%	60%	$105 - $138	0.7%
	Solar	$3578 - $16050	15% - 47%	$5.2 - $5.2	11.00%	9%	60%	$128 - $1533	2.0%
Vic	Wind	$2183 - $13421	18% - 41%	$7 - $7.3	11.00%	9%	60%	$105 - $544	0.4%
	Biomass	$2765 - $9693	57% - 80%	$20.9 - $62.7	12.00%	9%	60%	$92 - $298	0.3%
	Hydro	$3123 - $5619	35% - 58%	$3.1 - $3.1	11.00%	9%	60%	$126 - $136	0.2%
	Geothermal	$4677 - $5362	85% - 85%	$23 - $23	11.00%	9%	60%	$106 - $117	0.7%
	Solar	$5770 - $11183	15% - 50%	$5.2 - $5.2	11.00%	9%	60%	$204 - $1212	2.0%
NSW	Wind	$1976 - $4743	20% - 35%	$7.3 - $7.3	11.00%	9%	60%	$88 - $217	0.4%
	Biomass	$2363 - $4547	57% - 80%	$20.9 - $60.6	12.00%	9%	60%	$92 - $156	0.3%
	Hydro	$2382 - $2706	36% - 73%	$3.1 - $3.1	11.00%	9%	60%	$48 - $101	0.2%
	Geothermal	$4698 - $5810	85% - 85%	$23 - $23	11.00%	9%	60%	$106 - $125	0.7%
	Solar	$3578 - $11980	17% - 57%	$5.2 - $5.2	11.00%	9%	60%	$169 - $1146	2.0%
Qld	Wind	$2680 - $15285	28% - 35%	$7.3 - $7.3	11.00%	9%	60%	$116 - $618	0.4%
	Biomass	$3617 - $5144	35% - 80%	$20.9 - $62.7	12.00%	9%	60%	$105 - $275	0.3%
	Hydro	$2139 - $2348	27% - 38%	$3.1 - $3.4	11.00%	9%	60%	$80 - $122	0.2%
	Geothermal	$4894 - $5265	85% - 85%	$23 - $23	11.00%	9%	60%	$109 - $116	0.7%
	Solar	$3578 - $11183	20% - 57%	$5.2 - $5.2	11.00%	9%	60%	$169 - $910	2.0%
Tas	Wind	$2510 - $3508	33% - 42%	$7.3 - $7.3	11.00%	9%	60%	$112 - $149	0.4%
	Biomass	$1124 - $5708	57% - 80%	$7.7 - $41.8	12.00%	9%	60%	$31 - $195	0.3%
	Hydro	$2822 - $5403	10% - 46%	$3 - $3.1	11.00%	9%	60%	$141 - $400	0.2%
	Geothermal	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Solar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

A.10 Constraints

PLEXOS provides modelling flexibility through user-defined constraints. Constraints take the form of equations, consisting of a constant on the right hand side of the equation (RHS property), variables and coefficients on the left hand side and an operator such as less than or greater than sign (defined via the sense property).

The MMA database contains the major constraints reflected in the physical NEM, although frequency control ancillary service (FCAS) related constraints are not currently represented.

The majority of constraints in the database reflect network limits that AEMO enforces to manage the security of the power system. These constraints are categorised by their respective zone. They are sourced from AEMO's annual SOO publication, where they are provided separately as ANTS verification study constraints.

A.10.1 Conditions

Conditions are specified in the database to define certain events which are used in activating/deactivating objects or records in the simulation. All of the conditions in MMA's NEM database are used to activate constraints, or properties within constraints, and are grouped according to the object they apply to. For example, the limits on some of the ANTS transmission constraints are conditional on the number of units generating at certain power stations, and the conditions are used to determine the appropriate limit to be applied in any particular trading period.

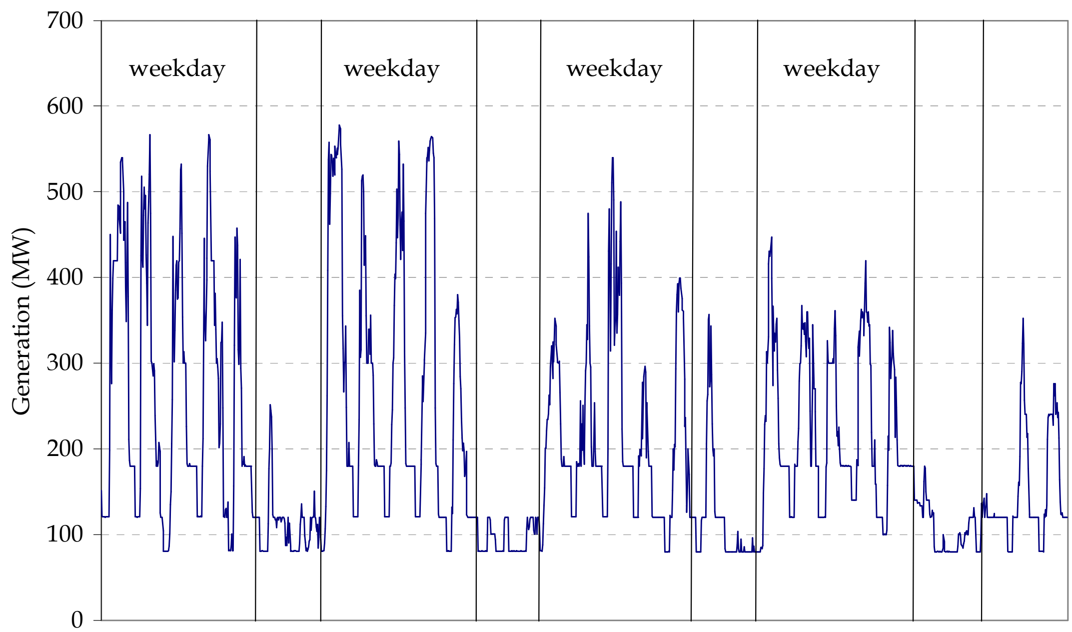
A.10.2 User Defined Constraints and Adjustments

Constraints are also used to model certain aspects of the market which would otherwise not be reflected from pure economic dispatch. FCAS requirement, commercial or strategic objectives and/or industrial load obligations may also influence dispatch but are not explicitly modelled in the MMA database. To approximate these market influences, MMA has specified its own NEM-specific constraints and adjustments which are summarised below.

- Torrens B: PLEXOS dispatch of the Torrens Island B does not produce outcomes observed in the NEM due to frequency control considerations that effectively keep at least two units generating in the weekend and three units generating during the weekday. This is evident in Figure A-18, which shows a typical monthly profile of Torrens Island B's historical dispatch. We model this through a constraint that forces generation from the Torrens Island B to be at least 80MW during weekends and 120MW during weekdays on a trading period basis.
- Pelican Point minimum stable level is defined substantially higher than the physical limit. This is because Pelican Points generally offers over 200 MW of capacity at $-990 and over 300 MW during spring and summer.

- Macquarie mothballing: Macquarie Generation has in the past operated only seven[29] of its eight base load units (Bayswater and Liddell) at any one time. Macquarie therefore typically holds back one Liddell unit, which only operate at high prices or during outages of other Macquarie units. This behaviour is modelled by a constraint with an appropriate penalty price, and the constraint is eventually relaxed around 2014.

Figure A-18 Typical dispatch from Torrens Island B, November-December 2008



- Gladstone mothballing: Stanwell appears to only operate five of its six Gladstone units at any one time. There is a penalty price on this constraint so that it can be relaxed in extreme circumstances.

- Bairnsdale minimum generation: To meet network constraints between 1am and 3am, the two Bairnsdale units are required to generate. Minimum generation constraints in these periods ensure that the units are dispatched at that time to support the network.

- Anglesea typically generates at maximum capacity (160 MW) in all periods. Therefore, to ensure this pattern of dispatch is observed Anglesea has a user-defined offer of 160 MW at - $1000/MWh.

- Barcaldine has hardly generated this last financial year and has been bidding most of its capacity at $8076/MWh. Energy offers are used to replicate this behaviour.

- Bayswater tends to operate at a capacity factor of about 75%–80%, however PLEXOS tends to dispatch Bayswater at a higher capacity factor than this. Therefore, a

29 It is noted that, at times, Macquarie has been operating all eight units for extended periods last year, suggesting that we may need to review this approach in the near future.

maximum capacity factor of 78% is imposed on these units. Since the maximum capacity factor is effectively an annual energy constraint it does not limit capacity in any one period. Hence, full capacity will still be available at times of high price.

- For summer 2009/10 Playford maximum capacity is limited to 200 MW due to plant issues which are expected to be resolved by 2010/11.
- Smithfield has user-specified energy offers to encourage the unit to be dispatched at maximum capacity during weekdays, and only at about half capacity during weekends, as observed historically, providing steam for its host Visy Industries.
- A maximum capacity factor for the year of 25% has been set for Laverton North, as its operating hours are restricted under the conditions of its licence from the Environment Protection Authority.
- HRL Fuel constraint: HRL's proposed IDGCC plant in the Latrobe Valley is set up as a multi-fuelled unit, burning either gasified coal or natural gas. The gasified coal is a lower cost fuel, but we have assumed that its availability will be limited in the first few years of operation given that the drying and gasification of the coal is a pilot project. Moreover, it is assumed that the gasifier is out on maintenance during April each year, further constraining the availability of gasified coal in that month.

APPENDIX B COSTS AND PERFORMANCE OF THERMAL PLANTS

The following table shows the parameters for power plants used in the PLEXOS model. Costs are reported in June 2009 dollars. The variable costs exclude the effect of the CPRS. The MW assumptions are generator terminal assumptions.

Plant	No. Units	Total Capacity (MW)	Scheduled Maintenance (Weeks pa)	Forced Outage Rate (%)	Available Capacity Factor (%)	Full Load Heat Rate (GJ / MWh)	Variable O&M ($/MWh)	Variable Fuel Cost ($/GJ)	Total Variable Cost ($/MWh)
NEW SOUTH WALES									
Bayswater	4	2760	2.5	2.0	93.3	9.8	2.08	1.41	15.88
Colongra	4	668	2.5	3.5	91.9	10.9	9.27	10.13	119.26
Eraring	4	2760	2.5	3.6	91.8	9.7	2.18	1.58	17.48
Eraring GT	1	40	2.5	3.5	91.9	23.5	9.27	22.46	537.16
Hunter Valley GT	1	51	4.0	3.5	89.1	24.2	9.27	22.46	552.26
Liddell	4	2100	2.5	3.1	92.3	11.1	2.30	1.41	17.94
Mt Piper	2	1400	1.0	0.9	97.1	9.7	2.36	1.48	16.74
Munmorah	2	600	43.1	9.6	15.6	10.9	1.80	1.48	18.00
Redbank	1	150	2.0	2.3	93.9	11.9	2.68	0.33	6.64
Smithfield	4	160	3.0	3.0	91.4	13.0	5.11	4.43	62.71
Tallawarra	1	435	2.5	3.0	92.3	7.1	3.41	4.80	37.27
Uranquinty	4	664	2.5	2.0	93.3	11.2	3.24	10.13	116.19
Vales Point	2	1320	3.8	4.1	88.9	9.9	1.35	1.53	16.46
Wallerawang	2	1000	4.8	7.6	83.9	10.2	1.80	1.53	17.48
QUEENSLAND									
Barcaldine	1	49	3.0	3.0	91.4	8.1	4.03	3.27	30.49
Braemar1	3	504	2.0	2.0	94.2	10.6	3.38	1.40	18.20

Plant	No. Units	Total Capacity (MW)	Scheduled Maintenance (Weeks pa)	Forced Outage Rate (%)	Available Capacity Factor (%)	Full Load Heat Rate (GJ / MWh)	Variable O&M ($/MWh)	Variable Fuel Cost ($/GJ)	Total Variable Cost ($/MWh)
Braemar2	3	519	2.0	2.0	94.2	11.6	3.38	1.40	19.64
Callide A	1	30	2.0	3.0	93.3	10.0	1.93	1.55	17.38
Callide B	2	700	2.0	3.0	93.3	10.5	1.53	1.15	13.55
Callide C	2	900	1.2	6.0	91.9	10.0	1.35	1.41	15.36
Collinsville	5	187	3.0	5.0	89.5	10.9	2.68	1.92	23.60
Condamine	3	135	2.0	2.2	94.1	7.6	3.38	0.93	10.45
Darling Downs	4	630	2.0	1.0	95.2	7.8	3.34	1.05	11.55
Gladstone	6	1680	2.4	4.6	91.1	10.8	1.18	1.81	20.85
Kogan Creek	1	744	3.0	3.0	91.4	9.9	0.81	0.73	8.07
Mackay GT	1	32	2.0	2.0	94.2	14.3	10.75	22.46	331.49
Millmerran	2	852	3.0	8.2	86.5	10.5	1.21	0.80	9.65
Moranbah	1	45	4.8	4.0	87.1	9.0	2.68	0.00	2.68
Mt Stuart GT 3	2	288	2.0	2.0	94.2	11.8	5.38	22.46	270.82
Mt Stuart GT	1	127	2.0	2.0	94.2	11.8	5.38	22.46	270.43
Oakey GT	2	332	2.0	2.0	94.2	11.6	5.38	6.90	85.10
QAL Cogen	1	153	2.5	1.0	94.2	7.0	3.37	0.00	3.37
Roma	2	68	4.0	5.0	87.7	13.5	5.38	3.27	49.49
Stanwell	4	1470	1.8	0.9	95.6	10.7	1.07	1.42	16.24
Swanbank B	4	480	3.0	10.0	84.8	13.3	2.68	1.71	25.38
Swanbank E	1	370	2.0	2.0	94.2	8.1	2.68	3.27	29.21
Tarong	4	1400	2.2	1.6	94.2	10.0	1.59	1.15	13.01

Plant	No. Units	Total Capacity (MW)	Scheduled Maintenance (Weeks pa)	Forced Outage Rate (%)	Available Capacity Factor (%)	Full Load Heat Rate (GJ / MWh)	Variable O&M ($/MWh)	Variable Fuel Cost ($/GJ)	Total Variable Cost ($/MWh)
Tarong North	1	443	2.4	1.6	93.9	9.5	1.11	1.15	11.96
Yabulu CCGT	2	256	3.0	2.0	92.3	9.4	2.68	3.16	32.51
Yarwun Cogen	1	167	2.0	2.0	94.2	10.9	3.38	3.27	38.94
SOUTH AUSTRALIA									
Angaston	30	50	0.5	7.5	91.6	11.1	11.54	22.46	261.11
Dry Creek	3	148	4.0	3.5	89.1	14.1	8.06	8.77	131.74
Hallett	1	187	4.0	0.0	92.3	15.4	9.20	8.77	144.55
Ladbroke Grove	2	86	3.0	2.3	92.1	10.0	6.72	2.70	33.73
Mintaro	1	90	4.0	4.6	88.0	16.3	8.06	8.77	150.65
Northern	2	546	2.8	2.1	92.6	11.4	0.70	1.42	16.90
Osborne	1	192	2.0	2.3	93.9	10.4	2.61	4.16	45.82
Pelican Point	1	474	3.0	1.0	93.3	7.2	2.68	3.91	30.80
Playford	1	240	6.0	5.0	84.0	17.2	1.92	1.42	26.25
Port Lincoln	3	75	3.0	3.0	91.4	10.7	8.06	22.46	249.02
Quarantine	4	92	4.0	3.5	89.1	10.4	8.42	8.77	99.40
Quarantine 5	1	128	4.0	3.5	89.1	10.3	9.81	4.58	56.94
Snuggery	3	66	4.0	4.6	88.0	15.0	8.06	22.46	344.51
Torrens Island A	4	504	4.0	5.0	87.7	10.8	8.06	4.58	57.49
Torrens Island B	4	820	4.0	5.0	87.7	10.5	2.01	4.58	50.09
TASMANIA									
BBThree	3	120	3.0	1.0	93.3	11.6	4.03	8.76	105.64

Plant	No. Units	Total Capacity (MW)	Scheduled Maintenance (Weeks pa)	Forced Outage Rate (%)	Available Capacity Factor (%)	Full Load Heat Rate (GJ / MWh)	Variable O&M ($/MWh)	Variable Fuel Cost ($/GJ)	Total Variable Cost ($/MWh)
Tamar Valley CCGT	1	203	1.9	3.0	93.5	9.5	2.68	4.35	44.05
Tamar Valley GT	1	58	3.0	1.0	93.3	11.6	4.03	9.81	117.96
VICTORIA									
Anglesea	1	159	1.0	1.5	96.6	15.3	1.35	0.14	3.46
Bairnsdale	2	92	3.0	1.0	93.3	10.5	4.03	4.38	50.23
Energy Brix	5	164	5.0	4.0	86.8	18.4	2.68	0.91	19.41
Hazelwood	8	1600	4.0	9.0	84.0	16.1	2.68	0.62	12.65
HRL IDGCC	1	440	3.0	0.0	94.2	7.2	3.24	1.00	10.50
Jeeralang A	4	232	2.1	1.0	95.0	13.8	8.06	3.73	59.34
Jeeralang B	3	255	2.1	1.0	95.0	12.9	8.06	3.73	55.99
Laverton North	2	340	2.0	2.3	93.9	11.6	4.03	4.99	61.90
Loy Yang A	4	2270	2.5	3.5	91.9	13.2	1.07	0.47	7.26
Loy Yang B	2	1050	2.5	3.0	92.3	13.1	1.07	0.47	7.24
Mortlake GT	2	553	2.5	4.0	91.4	10.8	3.67	2.66	32.46
NewPort	1	510	2.2	3.0	93.0	9.4	2.68	3.83	38.72
Somerton	1	160	4.0	5.0	87.7	13.5	2.68	3.83	54.39
Valley Power	6	336	2.1	1.0	95.0	13.8	8.06	3.73	59.34
Yallourn W	4	1487	3.0	6.0	88.6	14.9	1.35	0.48	8.53

* A very low marginal cost has been assumed for Anglesea to reflect the contractual arrangements for supply to the Pt Henry Smelter which encourages full output from Anglesea irrespective of pool prices.

** Redbank has also been assigned a low marginal cost consistent with its observed base load operation and its use of coal washery waste which otherwise has no value.

APPENDIX C EMISSONS ABATEMENT PROFILES FOR A TYPICAL WEEK

The emissions savings profile of a typical week by year is presented in Figure C-1 for the 150 MW and 500 MW cases, and for all scenarios in Figure C-2. Note that the first day of the typical week as it is presented is a Monday. As with the previous analysis presented in Chapter 6, the emissions savings profile is subject to other factors such as random noise resulting from different forced outage patterns across the scenarios. This is particularly an issue because of the small sample size, and it explains why the emissions savings occasionally dip below zero for the 150 MW and 500 MW cases.

Pre 2015, before the CPRS comes online, the emissions savings profiles for the 3,000 MW case are similar to the typical dispatch pattern of coal plant in NSW, which ramp up every morning and ramp down overnight to accommodate the daily load cycle. This pattern is somewhat discernable, although more noisy for the 500 MW case, and the noise is further magnified in the 150 MW case. The pre-CPRS emissions savings profiles for the larger wind cases are reasonably steady, having an average load factor of 78% for the 3,000 MW case, 68% for the 500 MW case, but only 42% for the 150 MW case. However, post 2015 the load factor of the emissions savings becomes progressively peakier, and reaches 68% for the 3000 MW case, and as low as 42% for the 500 MW case. Post 2015, the pattern in the emissions savings profile looks more like the daily load shape in the 3000 MW case, and a similar, although peakier, pattern also emerges in 2020 for the 500 MW case. This shows that the emissions savings are tending to align with the daily peak load, since by this time the carbon price is such that coal plants are marginal and ramp up and down during the day to service the daily peak.

Figure C-1 Emissions savings profile of typical week by year for 150 MW and 500 MW cases

Figure C-2 Emissions savings profile of typical week by year by scenario