Report to

Prime Minister's Task Group on Energy Efficiency

Electricity and Gas Market Benefits and Costs of an Energy Efficiency Obligation Scheme

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McLennan Magasanik Associates

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ABBREVIATIONS

ABARE	Australian Bureau of Agriculture and Resource Economics
ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
CCGT	Combined cycle gas turbine
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
EEO	Energy Efficiency Obligation
EEOS	Energy Efficiency Obligation Scheme
IEA	International Energy Agency
IMO	Western Australia's Independent Market Operator
LRET	Large-scale Renewable Energy Target
LRMC	Long run marginal cost
MEPS	Minimum Energy Performance Standards
MMA	McLennan Magasanik Associates
NEM	National Electricity Market
NFEE	National Framework on Energy Efficiency
NGGAS	NSW Greenhouse Gas Abatement Scheme
RECs	Renewable Energy Certificates
RET	Renewable Energy Target
SRES	Small-scale Renewable Energy Target
SWIS	South West Interconnected System
Task Group	Prime Minister's Energy Efficiency Task Group

1 INTRODUCTION

The Federal Government is considering the benefits and costs of a national energy efficiency obligation scheme. The scheme is designed to overcome market failures to the adoption of energy efficient appliances or practises.

To determine whether benefits exceed the cost, the Prime Minister's Task Group on Energy Efficiency (Task Group) commissioned McLennan Magasanik Associates (MMA) to estimate the costs and benefits associated with a hypothetical national energy efficiency obligation scheme. The hypothetical scheme modelled is a tradeable certificate scheme, along the lines of the NSW Energy Savings Scheme and the Victorian Energy Efficiency Target Scheme. Under this scheme, retailers and large electricity consumers are required to purchase a target amount of certificates to indicate they have undertaken a certain level of energy efficiency. Certificates are created from undertaking eligible energy efficiency programs.

MMA has used a range of models to determine the uptake of energy efficiency options and the associated energy savings. The costs of purchasing the options and benefits to the energy system are then estimated using sophisticated models of energy markets.

The findings of the analysis are outlined and discussed in this report.

All monetary values in this report are in mid-2010 dollar terms. Stated years refer to financial year ending June 30th of that year.

2 METHODOLOGY

2.1 Objectives

In this study, social benefits and costs are distinguished from market impacts. Social benefits and costs refer to the impact of an energy efficiency obligation scheme on the economic allocation of resources or the efficiency of resource use. To the extent that energy efficiency programs are taken up by end users, there will be a reduction of energy demand and a commensurate reduction in the resources used in energy production. The value of this reduction in resource use is estimated in this study.

In calculating any social benefits that may arise from implementing an energy efficiency obligation scheme, MMA's objective was to determine values and percentage deviations from the reference scenario (with no energy efficiency obligation scheme) for the following:

- Deferred and avoided investment.
- Deferred and avoided investment in network upgrades.
- Reduced fuel usage.
- Improvements in the reliability of energy supply.

Better allocation of resources arising from these benefits results in an increase in social wealth.

Market impacts refer to the impacts of energy efficiency programs on participants in the energy market. The key market impact of an energy efficiency programs will be on energy prices. Except in so far as the ensuing reduction in energy prices results in a reallocation of resources, this impact does not represent a social benefit as much of the reduction of energy price represents a transfer of wealth from energy producers to end users.

Market impacts are also estimated in this study. Impacts on wholesale and retail energy prices and generator profits are estimated.

It is important to note that whilst this study attempts to determine the benefits and costs of achieving a given energy efficiency target, it does not determine whether the energy efficiency obligations scheme is the best way to achieve the targets.

2.2 Approach

Energy market modelling was conducted using MMA's energy market database and modelling tools in conjunction with use of probabilistic market modelling software Strategist, licensed from Ventyx. For any given scenario Strategist represents the major thermal, hydro and pumped storage resources as well as the interconnections between the NEM regions. Economic optimisation tools (both internal and external to Strategist) are employed to adjust inter-related elements of the model and iteratively derive a solution that is more economically efficient. These elements may include thermal plant bids, up-take of renewable or thermal generation and appropriate retirement of existing generation. Average hourly pool prices are determined within Strategist based on thermal plant bids derived from marginal costs or entered directly, while renewable energy certificate prices are estimated outside of Strategist in MMA's Renewable Energy Market Management Model (REMMA) and are based on the net long run marginal cost of marginal renewable generation options.

Development of the future pool price path is driven by the supply and demand balance, with long-term prices being effectively capped near the cost of new entry on the premise that prices above this level provide economic signals for new generation to enter the market. Consequently price drivers include carbon prices under a CPRS, fuel costs, unit efficiencies and capital costs of new plant. Year to year prices will deviate from the new entry cost level based on the timing of new entry. In periods when new entry is not required, the market prices reflect the cost of generation to meet regional loads, and the bidding behaviour of the market participants as affected by market power. The market price forecasts developed have taken into account regional and temporal demand forecasts, generating plant performance, timing of new generation including renewable projects, existing interconnection limits and potential for interconnection development.

For renewable energy projects, the carbon price has a lesser impact while it is of insufficient level to sustain new renewable projects without additional certificate revenue. This is because any increase in carbon price raises pool prices and consequently reduces the required revenue stream from certificates in new projects. 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, and 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 renewable targets can be met more economically in places with high energy prices, such as in Western Australia.

Timing of new generation is determined from development of a generation expansion plan. MMA have used the PROVIEW module of Strategist to assist with this task and have developed a plan that minimises total costs of the generation system plus interconnection augmentation. This is similar to the outcome afforded by a competitive market. However, due to computational burden and structural limitations of the Strategist package, it is not feasible to complete in one analysis the establishment of an optimal expansion plan that is completely consistent with external scheme outcomes (e.g. level of renewable generation afforded by the MRET scheme) and with review of individual generator's contract positions and opportunities to game spot market prices. MMA therefore conduct a number of iterations of PROVIEW to develop a workable expansion plan based upon an initial estimate of renewable generation and then refine the expansion plan to achieve a sustainable price path applying market power where it is apparent and to obtain a consistent set of renewable and thermal new entry plant mix. The final expansion plan must meet reserve constraints applied in each region, and fall within maximum emergency energy outcomes and maximum loss of load hours' outcomes. Generators must behave rationally with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry. This is a conservative assumption as there have been periods when prices have exceeded new entry costs when averaged over 12 months. Infrequently used peaking resources are bid near the value of lost load or removed from the simulation to represent strategic bidding of these resources when demand is moderate or low.

3 ASSUMPTIONS

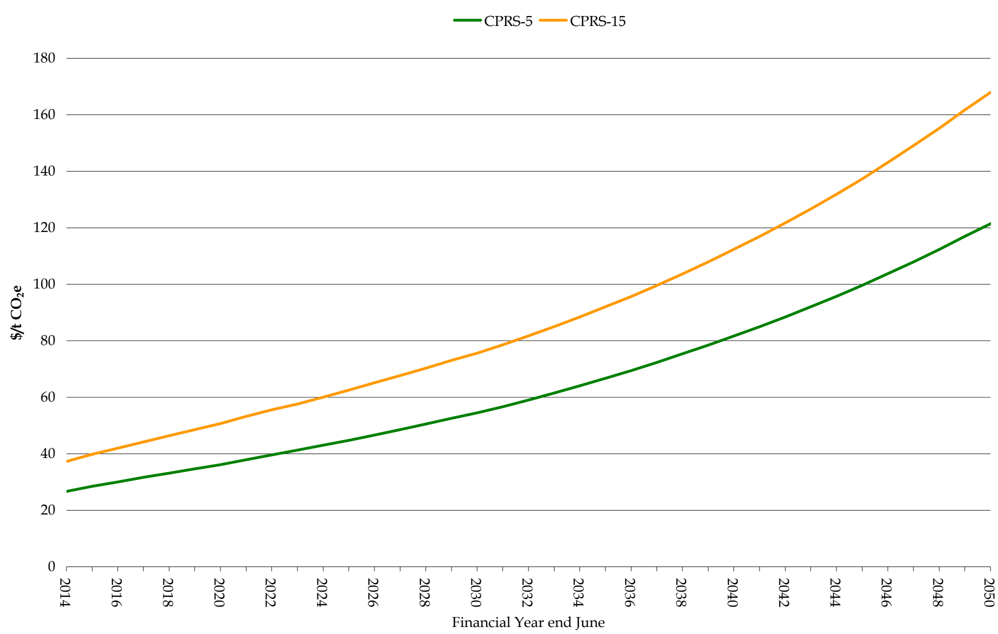
This section details the assumptions underlying the assessment of impacts of an energy efficiency obligation on the energy markets.

3.1 General Assumptions

3.1.1 Carbon prices

We assume the CPRS will commence on 1 July 2013 as a reference case, with -5% and -15% reduction targets by 2020. The carbon price paths assumed are shown in Figure 3-1. The prices are derived from studies of the CPRS undertaken by the Australian Treasury.

Figure 3-1: Carbon price path



Source: MMA analysis based on carbon prices contained in Australian Government (2008), *Australia's Low Pollution Future: The Economics of Climate Change Mitigation*, Canberra, updated to mid 2010 dollar terms.

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. The carbon price will be an additional cost to generators that will be passed through to end-users.

3.1.2 Demand

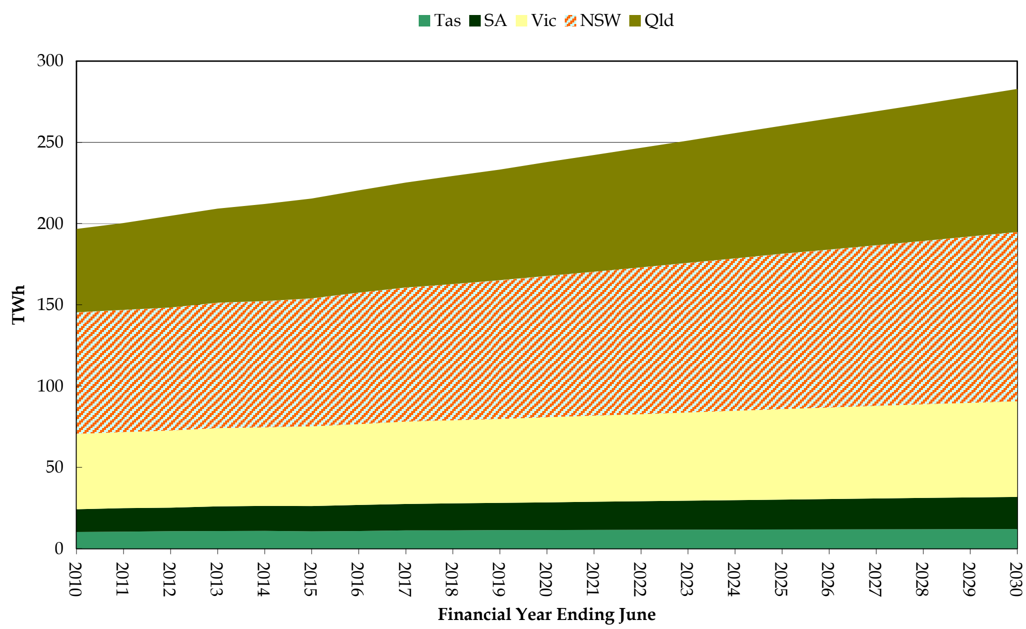
Three key demand parameters are used:

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

Demand projections for the NEM are obtained from AEMO. The AEMO projections are based on a native demand for electricity by consumers, but with loads supplied by embedded generation (due to the Renewable Energy Target Scheme and other measures) deducted. The AEMO projections also consider the impacts of the CPRS as originally designed with a 2011 start date. MMA has added back in the embedded load supplied by embedded renewable energy generation and also added back to demand from a delay in the CPRS, by assuming a price elasticity of -0.35.

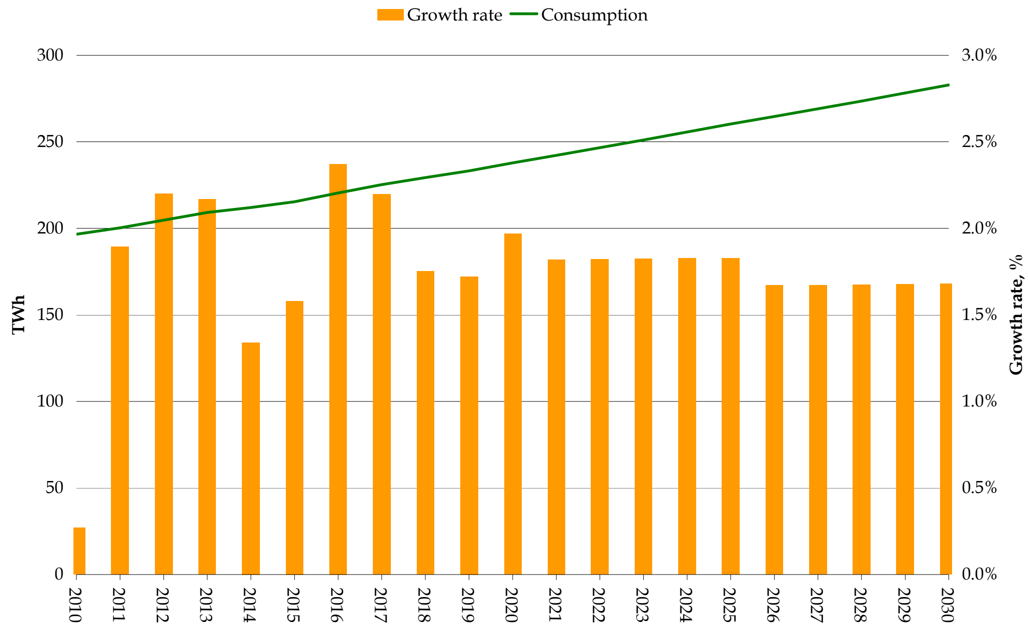
The projections for the medium demand growth case in the NEM show demand growing at 2% per annum from 2011 onwards reducing to 1.8% per annum from 2020.

Figure 3-2: Projections of energy consumption in the NEM, CPRS -5 scenario with median economic growth rates



Source: MMA analysis based on data published by AEMO.

Figure 3-3: Growth rate in energy consumption in the NEM



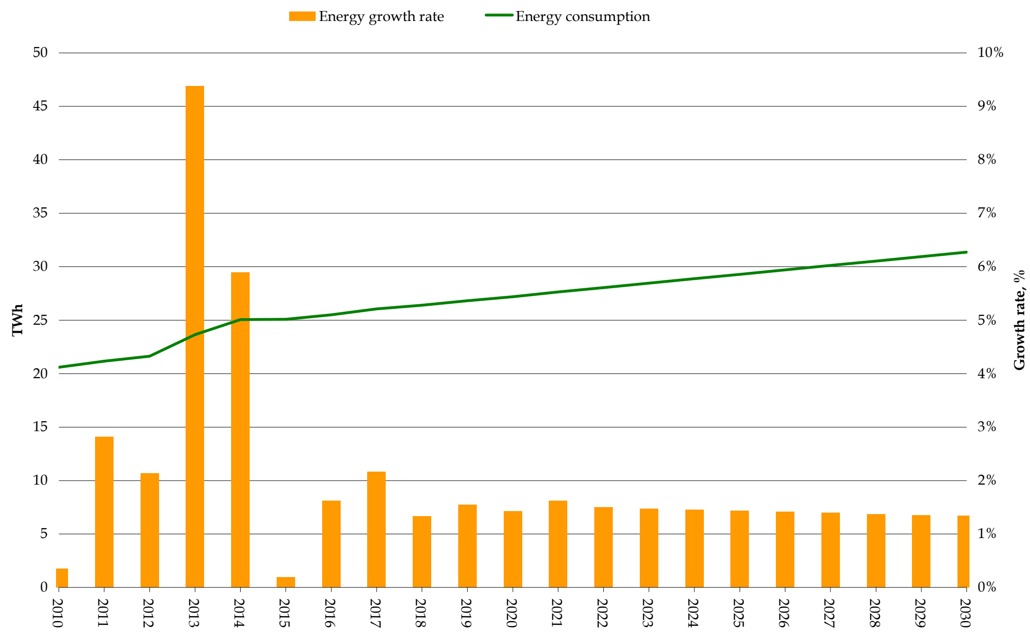
Source: MMA analysis based on data published by AEMO.

Demand projections for the South West Interconnected System (SWIS) are obtained from the IMO, the market operator for the SWIS. IMO's median case energy sent out forecasts for the contestable market and Verve Energy's Franchise for the period 2029/30 are used in the analysis. The forecasts are split between two regions, and projections of energy sent out at the alumina refineries are added, to create MMA's projections for electricity sent out. The compound growth rate for total electricity demand to 2020 is around 3.5% per annum (or 3.1% per annum if including the alumina refinery loads). Growth rates fall after 2020.

Projections of the summer peak demand at generator busbar are derived from forecasts of sent out peak demand provided by the IMO. Peak demand for each month is calculated based on the forecast summer peak demand and historical load profiles.

Using data provided by IMO, MMA derived a SWIS load profile. This data was normalised to the peak value for the 2004/05 and then modified to ensure consistency with energy sales and load factors. The load growth algorithm in the simulation model then used this historical load profile to forecast demand for the entire planning horizon, ensuring consistency with the annual peak and energy sales assumptions for the study period. This implies that the monthly pattern of energy sales and peak demand remains constant during the forecast period.

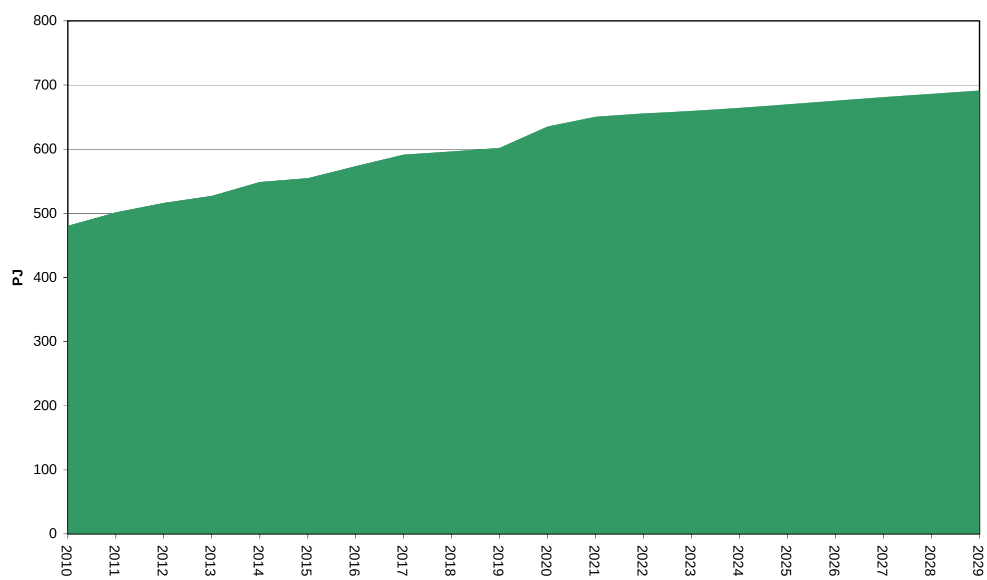
Figure 3-4: Projections of electricity demand in the SWIS



Source: MMA analysis based on data published by AEMO.

Gas demand projections were sourced from ABARE. Gas demand is also projected to grow in line with economic growth. Demand is projected to grow by around 3% per annum to 2020, but thereafter the growth rate is projected to slow to less than 1% per annum.

Figure 3-5: Projections of gas consumption (excluding for electricity generation)



Source: MMA analysis based on data published by ABARE.

3.1.3 Gas prices

MMA prepares gas price assumptions based on projected demand-supply balance in Australia. The gas resources and delivery infrastructure in this region are illustrated in Figure 3-6. MMA's in-house model, MMAGas, replicates the essential features of the Australian wholesale gas market:

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

MMAGas has been developed to provide realistic assessments of long-term outcomes in the Australian gas market, including gas pricing and quantities produced and transported to each regional market. The gas market in MMAGas is the market for medium to long-term gas contracts between producers and buyers such as retailers or generators. Competition between producers is represented as a Nash-Cournot game in which each producer seeks to maximise its profit subject to constraints imposed by its competitors. The role of buyers is replicated by modelling the activities of an arbitrage agent. Transmission costs are treated as cost inputs.

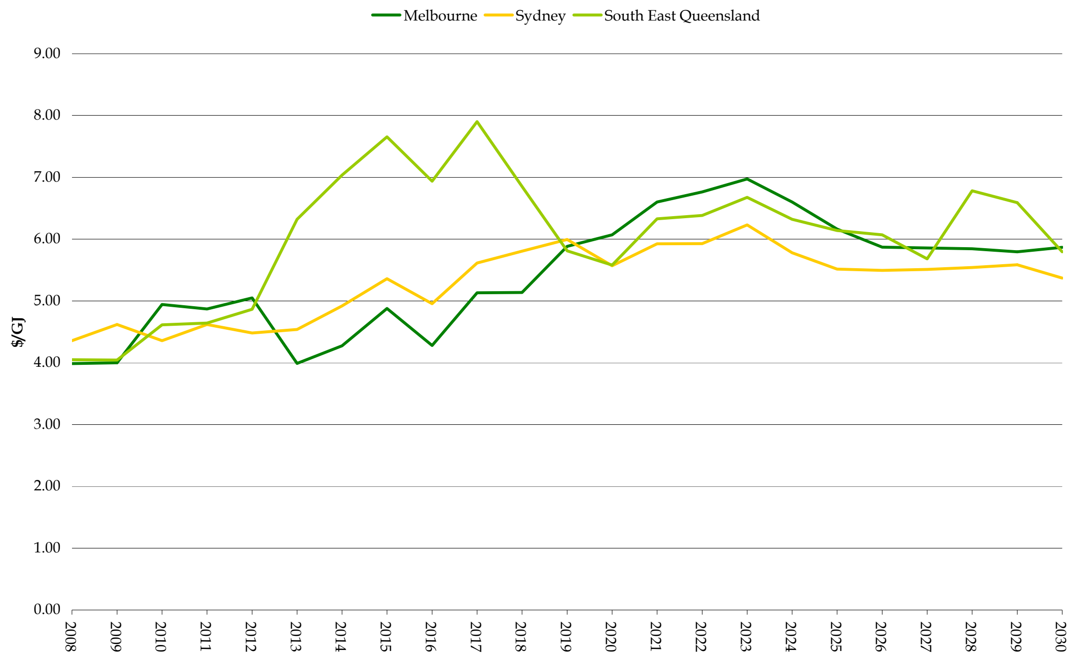
The gas prices derived from the MMAGas model input into Strategist by NEM region are presented in the charts below. Figure 3-7 shows gas costs for new entry plant throughout the forecast period. Similarly, Figure 3-8 shows the average cost of existing gas contracts, which represents the gas cost for incumbent plant throughout the forecast period. Gas prices are assumed to be similar for the CPRS -5 and CPRS -15 scenarios.

Gas price projections for Western Australia are shown in Figure 3-9 for new base load contracts. Existing contracts are at assumed contract price levels.

Figure 3-6: Gas resources and infrastructure, eastern Australia

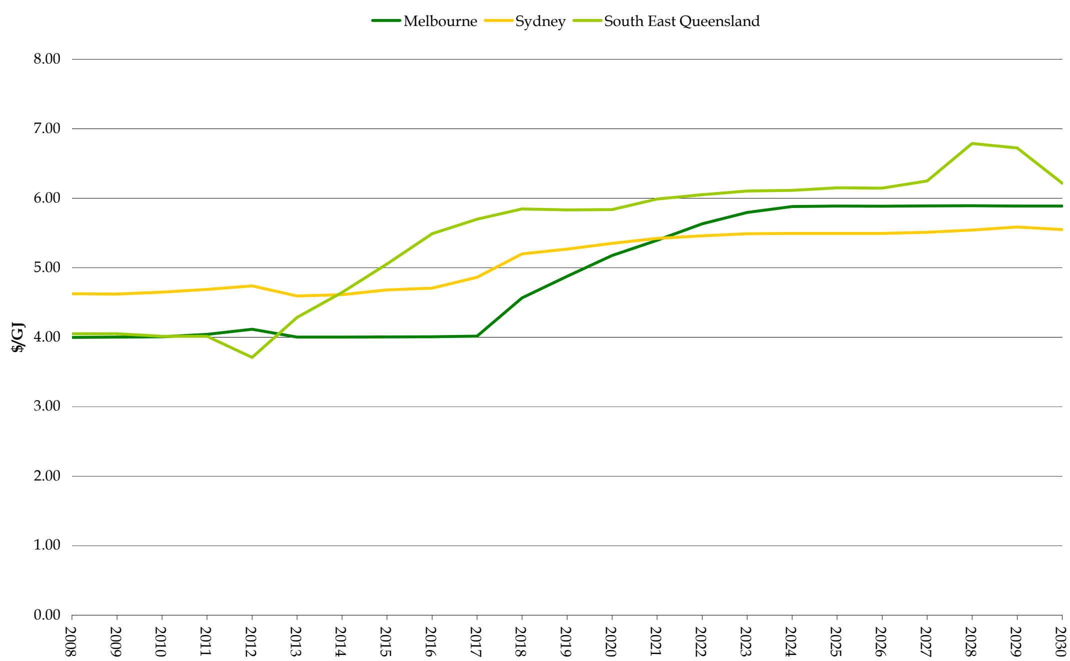
McLennan Magasanik Associates

Figure 3-7: Projected new contract gas prices for the eastern States



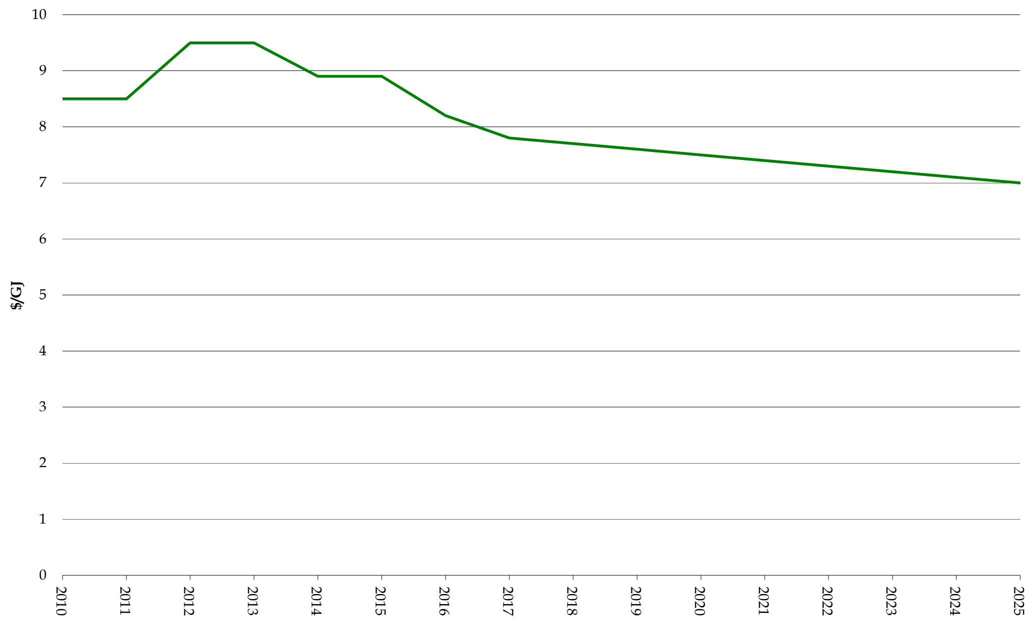
Source: MMA analysis.

Figure 3-8: Projected average contract gas prices for the eastern States



Source: MMA analysis.

Figure 3-9: Assumptions for gas prices in Western Australia



3.1.4 Other schemes

A major development with respect to renewable energy generation has been the expansion of the RET scheme to 45,000 GWh of additional renewable generation by 2020. The recent separation of small and large scale targets will likely see an increase in the adoption of small scale and large scale renewable energy technologies over the period to 2020. The Large Scale Renewable Energy Target (LRET) 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. LRET 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 LRET scheme, we have assumed that the current scheme parameters under the RET would continue to operate with an increased target from 2010 onwards. The 41,000 GWh target continues until 2030.

The Small Scale Renewable Energy Scheme (SRES) provides a fixed nominal price of $40/MWh for small scale systems such as solar water heaters and roof-top PV systems[1].

Other types of schemes operating in Australia are described in Appendix C.

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[1] Uptake of solar and heat pump water heaters and roof-top PV systems under the SRES is treated in the model as a laod modifier – that it reduces the amount of energy consumption by the energy saved from uptake of these technologies.

3.2 Assumptions - NEM

3.2.1 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 existing thermal plants are shown in Table 3-1. The parameters underlying these costs are presented in detail on a plant by plant basis in Appendix B. MMA also include the net present value of changes in future capital expenditure that would be driven by fuel consumption for open cut mines that are owned by the generator. This applies to coal in Victoria and South Australia.

Table 3-1: Indicative average variable costs for existing thermal plant

Technology	Variable cost, $/MWh	Technology	Variable cost, $/MWh
Brown Coal – Victoria	$7 - $11	Brown Coal – SA	$22 - $28
Gas – Victoria	$44 - $63	Black Coal – NSW	$20 - $23
Gas – SA	$37 - $178	Black Coal - Qld	$8 - $22
Oil – SA	$260 - $320	Gas - Queensland	$25 - $100
Gas Peak – SA	$100 - $180	Oil – Queensland	$250

3.2.2 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 by generator are shown in Appendix B.

3.2.3 Market structure

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

- Victorian generators are not further aggregated
- NSW generators remain under the current structure in public ownership
- The generators' ownership structure in Queensland remains as public ownership
- The SA assets continue under the current portfolio groupings (Optima in the TRUenergy portfolio and Synergen in the International Power portfolio with Pelican Point and Hazelwood Power).

This market arrangement provides the following features:

- NSW generators dominate the price making in Victoria and NSW due to their higher variable costs than the brown coal businesses and the coal fired surplus which leaves the Victorian gas fired business with little dispatch or market influence initially in Victoria.
- Victorian brown coal generators are assumed to maintain a price-taking role which is strengthened as demand grows in Victoria and the brown coal plants become fully loaded. Southern Hydro is also assumed to be a price taker in Victoria.
- Victorian brown coal generators may contribute to price making at times of very high peak demands when supply conditions permit.
- Since the commissioning of QNI and Millmerran, NSW generators also influence prices in Queensland.
- 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.

3.2.4 Relationship between contract position and bidding behaviour

Bidding of capacity depends on the contracting position of the generator. Capacity under two-way contracts will either be self-committed[2] for operational reasons or bid at marginal cost to ensure that the plant is earning pool revenue whenever the pool price exceeds the marginal cost. Capacity which backs one-way hedges will be bid at the higher of marginal cost and the contract strike price, again to ensure that pool revenue is available to cover the contract pay out.

In Strategist, contracts are not explicitly modelled. Rather we typically have half to ¾ of the capacity of base load and intermediate plants bid at marginal cost to represent the contracted level. If this produces very low pool prices bid prices are represented at a level higher than marginal cost to represent periods of price support that would be necessary to support the spot and contract market from time to time.

3.2.5 Bidding and 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 3-2 below. 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 increases by 300 MW, however this only translates to an 80 MW increase in minimum reserve levels for the region.

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2 Self-committed means that the generator specifies the timing and level of dispatch rather than NEMMCO and this is taken as a zero bid when setting pool prices. If generators are required to off-load below their self-commitment level, a negative pool price will be declared for generators and customers.

Table 3-2: Minimum reserve levels assumed for each state

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

Source: AEMO (2009).

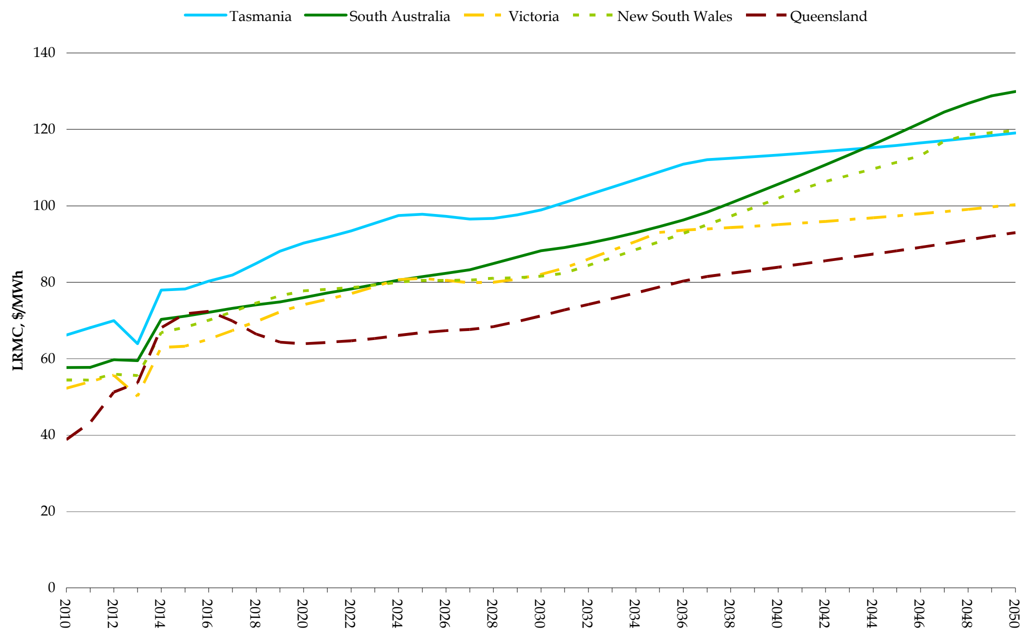
After selecting new entry to meet AEMO's minimum reserve criteria, MMA's pool market solution indicates whether prices would support additional new entry under typical market conditions and these are included in the market expansion if required. We assume that:

- Some 75% of base load plant capacity will be hedged in the market and bid at close to marginal cost to manage contract position.
- New entrants will require that their first year cash costs are met from the pool revenue before they will invest.
- The next new entrants in Victoria will be either peaking plant to meet reserve requirements or new combined cycle plant when such plant can achieve at least 50% capacity factor. MMA does not believe that new brown coal is yet ready to be the price setter for new entry in Victoria.
- Infrequently used peaking resources are bid near VoLL or removed from the simulation to represent strategic bidding of such resources.

New entry prices are shown in Figure 3-10 and

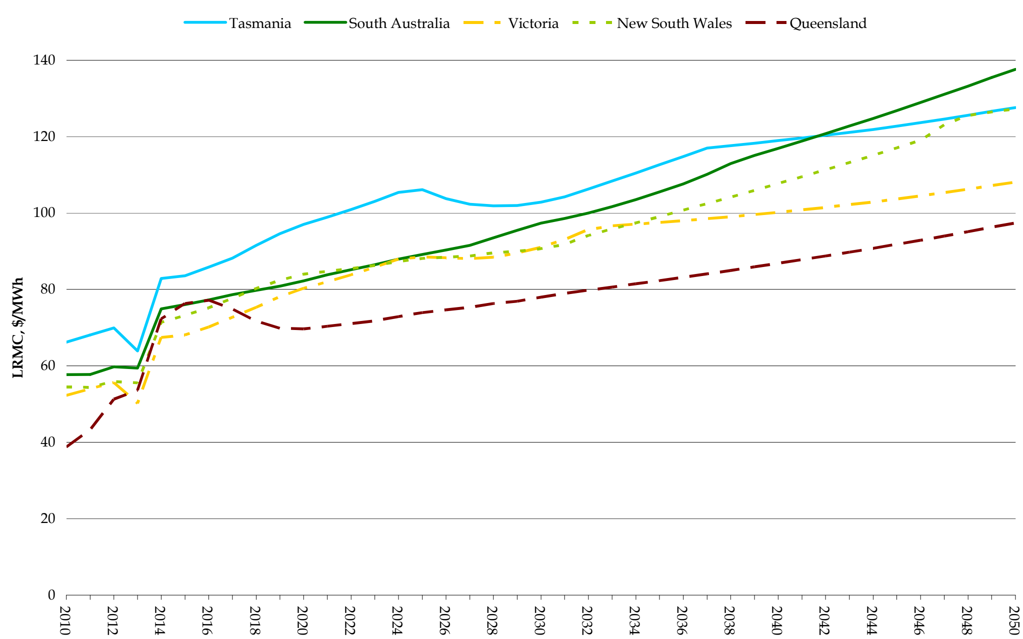
Figure 3-11. Cost and financing assumptions used to develop the long-term new entry prices are provided in Table 3-3. The real pre-tax equity return was 17% and the CPI applied to the nominal interest rate of 9% was 2.5%. The capital costs are generally assumed to escalate at CPI-1% until they reach the long-term trend. New technologies have higher initial costs and greater rates of real cost decline up to -1.56% pa for IGCC. The debt /equity proportion is assumed to be 60%/40%. This gives a real pre-tax weighted average cost of capital of 10.60 % pa. It is assumed that the higher risks emerging in the electricity generation sector from CPRS will require these higher equity returns.

Figure 3-10: LRMC for new plant, CPRS -5 scenario



Source: MMA analysis. Long run marginal costs are for 95% capacity factor plant, which is representative of the prices that would be required on a time weighted average basis.

Figure 3-11: LRMC for new plant, CPRS -15 scenario



Source: MMA analysis. Long run marginal costs are for 95% capacity factor plant, which is representative of the prices that would be required on a time weighted average basis.

The capacity factors in Table 3-3 are deliberately high to allow us to approximate a time-weighted new entry price in each state that can rapidly be compared to the time-weighted price forecasts to determine whether or not new entry would be encouraged to enter the market. These capacity factors do not necessarily reflect the levels of duty that we would expect from the units. The unit's true LRMC measured in $/MWh is higher than this level. For example, we would be more likely to find a new CCGT operating in Victoria with a capacity factor of around 60% to 70% rather than the 92% as indicated in the table. Ideally, in determining the timing of new entry of such a plant we would compare the new entry cost of a CCGT operating at this level against the time-weighted prices forecast in the top 60% to 70% of hours. However, this would require more detailed and timely analysis and in our experience does not yield any significantly different price path.

Table 3-3: New entry cost and financial assumptions for 2009/10

	Type of Plant	Capital cost, $/kW	Available capacity factor	Weighted cost of capital, % real	Interest rate, % nominal	Debt level
SA	CCGT (a)	$1,150	92%	10.60%	9%	60%
Vic	CCGT (a)	$1,150	92%	10.60%	9%	60%
NSW	CCGT (b)	$1,350	92%	10.60%	9%	60%
NSW	Black Coal	$2,200	92%	10.60%	9%	60%
Qld	CCGT (b)	$1,350	92%	10.60%	9%	60%
Qld	Black Coal (Tarong)	$2,200	92%	10.60%	9%	60%
Qld	Black Coal (Central)	$2,200	92%	10.60%	9%	60%

Note: (a) extension to existing site; (b) at a green field site. Source: MMA analysis.

3.3 Assumptions – SWIS

This section details the electricity market assumptions underlying the analysis of impacts in the South West Interconnected System (SWIS) in this study. The key assumptions for the analysis are outlined in Table 3-4. Note that most of the assumptions described in the base case are common to the high case. The gas prices are in accordance with the projections from the MMA-Gas model.

Table 3-4: Key assumptions

Feature	Base
Load Growth	IMO medium economic growth
Gas Prices	Standard forecast at world benchmark prices, which sees gas prices increase by 1% per annum in real terms.
New Entry Capital Costs	40% initial increase to base costs, declining at CPI-3% until they reach a CPI-1% long-term trend in capital costs

The current high new entry costs is not expected to be sustained indefinitely. We expect prices 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%.

3.3.1 Trading arrangements

The wholesale market for electricity in the SWIS is structured into:

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

The SWIS is relatively small, and a large proportion of the electricity demand is from mining and industrial use, which is supplied under long-term contracts. Considering these features, the bilateral contracts market continues to underpin trading in this market, with a residual day ahead trading market (called the STEM) supporting bilateral trades. This residual trading market allows contract participants to trade out any imbalances, and also allows small generators to compete where they would otherwise not be able to, due to their inability to secure contracts.

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

The ancillary services market is the responsibility of the Western Australian Independent Market Operator (IMO). The IMO is required to determine the least cost supplies to satisfy the system security requirements. Both independent generators and Verve Energy could be ancillary reserve providers, but at least initially it is envisioned that Verve will need to provide all spinning reserve under contract with system management.

All market participants pay for the ancillary services. In MMA's model, it is assumed that there is a market for trading spinning reserve. Providers receive revenue for this service, and the cost is allocated to all generators above 115 MW with the largest cost disproportionately allocated to the largest unit.

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

3.3.2 Structure of generation

The State Generator, Verve Energy, has been disaggregated vertically from the rest of Western Power but not horizontally.

To encourage competition, Verve Energy will not be automatically allowed to build new plant to replace its old or inefficient plant. The assumption for the analysis is to allow Verve Energy to bid for new entry generation as long as its overall generation capacity does not exceed 3,400 MW, in line with Government regulations.

3.3.3 Generation assumptions – existing units

Verve Energy

Verve Energy has 11 power stations operating in the SWIS. The Muja stations operate as base load stations with capacity factors of 70% to 95%. The Kwinana steam plants and the Mungarra gas turbine operate as intermediate plants with capacity factors of about 40%, while the Pinjar gas turbines operate as peaking plant with 10% to 20% capacity factor. Cogeneration plants are assumed to operate as must-run plants due to steam off-take requirements.

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

The Kwinana C power station is modelled to burn both coal and gas, but this station is assumed to close in 2013.

Other generators

Private generating capacity, including major cogeneration, is detailed in Table 3-5. The capacity is mostly comprised of gas-fired generation. There has been a large increase in privately-run generating capacity due to substantial falls in gas costs and the gradual deregulation of the generation sector. Over the 1996-97 period, some 324 MW of privately-owned generation capacity was commissioned, at Kwinana and the Goldfields.

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

Power generation from gas in the Goldfields commenced in 1996. Southern Cross Power generates from 4 x 38 MW LM6000 gas turbine stations for its Mount Keith, Leinster, Kambalda nickel mines and its Kalgoorlie nickel smelter. The stations are expected to use about 14 PJ of gas pa (37 TJ/d), sourced from the East Spar field. Goldfields Power has constructed 110 MW of capacity (3 x LM6000 gas turbines) east of Kalgoorlie to supply the SuperPit, Kaltails and Jubilee gold projects.

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

Table 3-5: Generating plants over 10 MW capacity in the SWIS

Company	Fuel	Capacity in summer peak, MW sent out	Maintenance (weeks per year)	Forced outage (%)	Heat rate GJ/MWh
Alcoa	gas	212	3.8	2	12.0
BP/Mission	gas	100	3.8	2	8.0
Southern Cross	gas	120	3.8	4	11.7, 12.7
Goldfields Power	gas	90	3.8	1	9.5
Worsley	gas	27	3.8	2	8.0
Wambo Power	gas	350	3.0	2.0	7.4
Kemerton	gas, liquid fuel	308	1.0	1.5	12.2
Alinta Wagerup	gas	351	3.0	2.0	11.2
Alinta Pinjarra	gas	266	2.0	2.0	6.5
Bluewaters	coal	400	3.0	3.0	9.7

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

3.3.4 New thermal units

To meet the anticipated growth in demand in the SWIS beyond 2009, additional generation plants will be required. Furthermore, Verve Energy has committed to retiring old and inefficient units –Kwinana B, Kwinana A, and Muja A/B have already been retired – with Kwinana C mooted for retirement in 2013.

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

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

The wind farms at Walkaway and Emu Downs are assumed to continue to operate past 2030, with a capacity factor of around 35%. Co-firing at Muja at 5% output for one unit is also assumed to continue during the study period.

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

Table 3-6: Assumptions for new thermal generation options

Option	Sent-out capacity, MW	Capital cost, 2010, $/kW so	De-escalater, % pa	Heat rate at maximum capacity, GJ/MWh	Variable O&M cost, $/MWh	Fixed O&M cost, $/kW
Black coal						
Subcritical coal	184	1,879	0.5	9.6	3	30
IGCC	187	2,673	1.5	9.1	2	44
IGCC with CC	180	3,688	1.5	11.4	3	50
Natural gas						
CCGT	235	1,467	0.5	7.4	3	22
Cogeneration	235	1,740	0.5	5.0	3	20
CCGT with CC	216	2,201	1.0	8.6	4	44
OCGT with CC	135	742	1.0	11.0	4	29

Note: CC = carbon capture. Sources: IEA and MMA database of project capital costs.

3.3.5 Fuel assumptions

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

Coal Prices

In the MMA model, coal prices after 2010 are assumed to be $45/t on a delivered basis with an energy content of 19.3 GJ/t. This coal price is MMA data based on market knowledge.

Coal prices are assumed to increase by 1% per annum in real terms.

Gas prices

MMA assumes that gas supply will be priced at the well-head as shown in Figure 3-9. These assumptions are based on projections by MMAGas.

The transport charge is $1.10/GJ escalating at 75% of CPI.

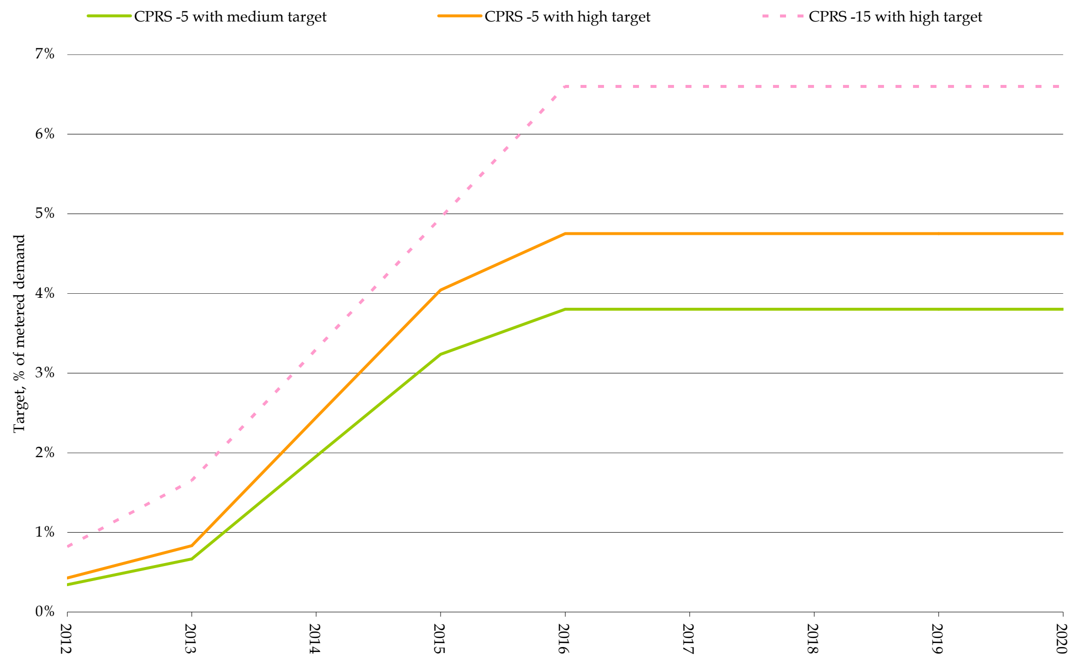
All stations owned by Goldfields Power and Southern Cross Power are modelled to use gas with a gas transmission charge of $3/GJ for gas supplied to the Goldfields region, reflecting the distances gas needs to be transmitted in this region, deflating at 75% of the CPI.

3.4 Scenarios

Energy market impacts were modelled for two carbon price and four policy scenarios with different target trajectories for a hypothetical energy efficiency obligation scheme. The policy scenarios assume the energy efficiency obligations scheme commence on 1st July 2012 and end on 30th June 2020. A slow ramp up to the ultimate target has been assumed to allow liable parties time to adjust to the new measure (see Figure 3-12 and Figure 3-13).

Figure 3-12: Ramp up targets for electricity savings, percent of metered demand

Figure 3-13: Ramp up targets for gas savings, percent of metered demand



Source: Prime Minister's Task Group on Energy Efficiency.

For the CPRS -5 carbon price trajectory, the following energy savings scenarios were modelled:

- *CPRS -5 only*: No energy savings initiative, with the CPRS commencing 1 July 2013.
- *CPRS -5 with low target*: CPRS -5 with a 4% target for energy savings from 2015 to 2020 for electricity. There was no target for gas savings options.
- *CPRS -5 with medium target*: CPRS -5 with a 5.94% target for energy savings from 2015 to 2020. A target for gas options was also applied, with a target of 3.8% from 2015 to 2020.
- *CPRS -5 with high target*: CPRS -5 with a 7.42% target for energy savings from 2015 to 2020. A target for gas options was also applied, with a target of 4.75% from 2015 to 2020.

For the CPRS -15 carbon price trajectory, the following scenarios were modelled:

- *CPRS -15 only*: No energy savings initiative, with the CPRS commencing 1 July 2013.
- *CPRS -15 with high target*: CPRS -5 with a 11.5% target for energy savings from 2015 to 2020 for electricity. A target for gas options was also applied, with a target of 6.6% from 2015 to 2020.

In all cases, it was assumed that there was a rebound effect, which was assumed to be 20% of the purported savings, in line with estimates in the international literature. It was assumed that once the energy efficient appliances were at the end of its technical life (after the expiry date of 2020 for the energy efficiency obligation), only 50% were replaced with a model with the same or better energy efficiency. It was assumed that 50% were replaced with a less efficient model to reflect the continuance of market failures (split incentives, lack or costly acquisition of information) in the absence of any measure to overcome those failures.

Present values of benefits and costs were estimated using a discount rate of 6%. All benefits and costs are in real mid 2010 dollar terms. To determine benefits and costs, it was assumed that energy efficiency savings in 2020 were carried forward to the end of the technical life of the appliance. Present values of benefits and costs were calculated for the period 2012 to 2040, which should cover the economic life of energy efficient options adopted in 2020, the final year of the proposed scheme.

4 ENERGY EFFICIENCY POTENTIAL IN AUSTRALIA

4.1 How Do Savings Arise

Under a tradeable certificate scheme for energy efficiency, obligated parties (that is, energy retailers) would be required to source and acquire certificates according to their individual liabilities for encouraging energy efficient practises or pay a financial penalty. The obligated parties could either source the certificates by investing directly in eligible activities or by purchasing certificates from others. The certificate price would ultimately be established by the market, but would need to be sufficient to stimulate the level of investments in energy efficiency required to meet the targets.

A key premise of this analysis is that there are a range of energy efficient appliances and processes that are not being adopted because of market failures or some other non pecuniary barrier. Numerous studies have shown based on technical data on the costs of energy efficient practises and estimates of potential savings, that there is a large potential to reduce energy demand at low cost or even with a positive return. Recent analysis of energy efficiency opportunities across all sectors in Australia shows that even in the commercial and residential sector where Australia's energy intensity is average within the OECD, significant energy efficiency improvements could be made. While estimates vary widely, various studies have found that energy efficiency improvements of between 13 and 73% in the residential sector, 10 and 70% in the commercial sector and 6 and 46 % in the manufacturing sector are available[3].

The fact that these options are not being adopted is presumed to be due to the presence of the market failures. These market failures and barriers include information failures, transaction costs, incentive misalignments, public good aspects of information and research and development, capital constraints and behavioural and organisational barriers.

4.2 Model of Energy Efficiency Uptake

MMA used a model of energy end use by customer class to estimate the energy efficiency potential. The model derives a cost curve for energy efficiency options, which maps the potential amount of energy saving for each energy efficiency option in ascending order of the net long run marginal costs of the options. The net long run marginal cost of each option is equal to average cost of adopting the option (where capital and operating costs are averaged over the technical lifespan of the option) minus the average value of energy savings provided by the option (based on market prices). Some energy efficient options may have a negative long run marginal cost, implying net benefit to energy users over the

3 For a review of these studies, see MMA (2008), *Defining an National Energy Efficiency Strategy – Part I*, report to The Climate Institute

technical life of the option. The lack of adoption of these options reflects the market failures that currently hinder the uptake of energy efficient appliances and equipment.

The model comprises the following elements:

- Load is segregated into residential, commercial and industrial sectors.
- For the residential sector, the model segregates by type of dwelling and by energy service (heating, lighting, etc).
- For the commercial sector, the model is segregated into building type and function – e.g. retail and wholesale premises, construction, public utilities, and offices.
- For the industrial sector, activities are broken down into major energy using activities in each state.

For this study, published projections (AEMO, ABARE) of energy demand by sector were used. The model of energy end use was then used to determine the proportion of this energy demand that is reduced through energy efficiency programs, based on the relative benefits to each sector of adoption of more efficient appliances and practises subject to commercial and other barriers to this uptake.

Energy efficiency options were modelled by type of option. Each option was defined by costs of the option (capital, variable and fixed operating costs), energy savings, instantaneous demand foregone, and constraints on the rate of adoption. Costs of installing equipment and ongoing energy cost savings were used to develop the long run marginal cost for each of the options by year of installation and by the level of installations.

Uptake of each of the options may be limited in the model to a chosen level of penetration and introduced over a specified period to reflect the natural inertia in the adoption of new technologies.

For this study, the energy efficiency options were confined to those options that would not be adopted without the measure but had net benefit to energy users over the economic life of the option.

4.3 Energy Efficient Options

We assume all options are available to be adopted in 2012, but there are technical and or social limits to how much can be achieved by 2020 and by 2030.

For each option, costs of adoption and energy savings from adoption are calculated. For each year of the scheme, the cost of adoption and the value of energy savings are calculated. Costs include the upfront purchase costs and ongoing operating costs. Energy savings are valued using projected energy prices. An option were the present value of the energy savings over the life of the option exceed the costs implies that there is a net benefit to adoption of the option.

The modelling assumed that the choice of a more energy efficient appliance was dependent on its payback period. A defined payback period was used, which was less than the economic life of the equipment being adopted. In principle, benefits and costs to end users should be calculated over the economic life of the equipment. A shorter period was used as a proxy for other costs and barriers not captured in the calculation. Examples include poorer quality amenity from energy efficient appliances (i.e. lower quality light from fluorescent light globes) and the opportunity cost of management time in selecting and installing energy efficient equipment.

4.3.1 Residential

For the residential sector, the model included the following energy efficient options:

- *Improvement of building envelope for new homes*. With this option, energy savings were assumed to occur through improvements to the building shell.
- *Replace light globes*. This option has lights in new homes to be most efficient available technologies for lighting. This goes above the ban imposed by the federal government on incandescent lights. The efficiency of all installed lights must be best available for intended purpose.
- *Water heating*. This option involves new gas-fired water heating to be more energy efficient, with an improved insulation on the system. The option includes insulation in the associated pipes.
- *Water heater replacement*. This option involved the early replacement of water heaters in existing homes (before the time units would normally be replaced).
- *Water heater insulation*. This option involved retrofitting insulation to water pipes and tanks in existing systems.
- *Roof space, wall and floor insulation program*. This option involved improving insulation and shading at existing homes.
- *Window shading*. This option involved retrofitting shading to west and north faces of existing houses that would benefit from the shading.
- *Phase out of halogen lights*. This option involved phasing out halogen lamps commencing from a specified year.
- *Time switch lights*. This involved fitting time switches and motion sensors to exterior lighting.
- *More efficient appliances*. This option involved consumers purchasing appliances with world best practise efficiency rating (i.e. encouraging consumer to purchase appliances above the federal minimum standards). Specific options for white goods, consumer electronics (televisions, computers, stereos), and air conditioners were modelled.

Key assumptions for each program are shown in Table 4-1.

Table 4-1: Assumptions for key energy efficiency options for residential sector

	Max efficiency gain	Max penetration rate	Additional cost per unit, $	Phase in, years	Annual stock turn
Efficient lighting	9%	35%	200	15	10%
Water Heater Efficiency	30%	30%	1,500	15	7%
Water Heater Replacement	30%	30%	1,500	15	7%
Water Heater Insulation	24%	30%	200	15	7%
Roof Space Insulation	6%	30%	1,920	15	3%
Window Shading	6%	25%	500	15	4%
Replacement of Halogen Lights	10%	50%	250	13	7%
Time Switching Outdoor Lights	30%	30%	200	13	10%
Refrigeration Efficiency	9%	80%	400	13	5%
Consumer Electronics Efficiency	7%	80%	500	15	7%
Air Conditioning Efficiency	12%	70%	500	15	5%
Reduction of Thermostats	9%	50%	0	10	4%
Sealing of Window Drafts	3%	50%	209	10	5%
Sealing of Door Drafts	3%	50%	369	10	5%
Better Wall Insulation	3%	50%	1,569	15	3%
Floor Insulation	2%	50%	1,920	15	3%
Film on Windows	3%	50%	2,500	15	3%
Double Glazing	6%	30%	4,900	15	2%
Double Glazing with Film	9%	30%	6,400	15	2%
Standby Power Controllers	1%	20%	200	10	2%
Ducted Space Gas Heater Efficiency	6%	8%	400	15	1%
Ducted Reverse Cycle Air Conditioner	6%	15%	500	15	1%
Replace Electric Radiator	3%	10%	200	10	1%
Replace Electric Fan Forced Heater	6%	15%	450	10	2%
Efficient Stand Alone Gas Heater	3%	6%	300	10	1%
Efficient Stand Alone Electric Heater	6%	25%	350	10	3%
Efficient Top Loader Clothes Washer	12%	37%	450	15	2%
Efficient Front Loader Clothes Washer	41%	19%	380	15	1%
Efficient Freezer	17%	34%	300	15	2%
Efficient Dishwasher	9%	44%	300	10	4%
Remove Spare Refrigerator	5%	17%	200	15	1%
Remove Spare Freezer	5%	1%	200	15	1%

Source: MMA analysis using data sources listed below.

The uptake rates were assumed to be a function of the number of households and the proportion of households that replace an appliance in each year. There are constraints on the maximum number of households that could adopt an efficient appliance (for example, there is a limit on the number of homes that could install roof installation set by ABS data on the number of homes without roof insulation). For each appliance or practise, there is an assumption of a phase in period over which economic options are fully adopted[4]. In

[4] Assumptions on the number of years over which an option can become fully adopted are shown in the phase in column of Table 4-1.

each year of the phase in period, there is a limit on the maximum number of households that can adopt an option.

Box 4-1: Factors constraining uptake of energy efficient appliances

Uptake of each energy efficient option under the energy efficiency obligation scheme is governed by payback. Options with payback periods to end-users less than a set period are assumed to be attractive for adoption. The set periods are less than 3 years for residential energy efficient options and less than 5 years for energy efficient options for the commercial and industrial sectors.

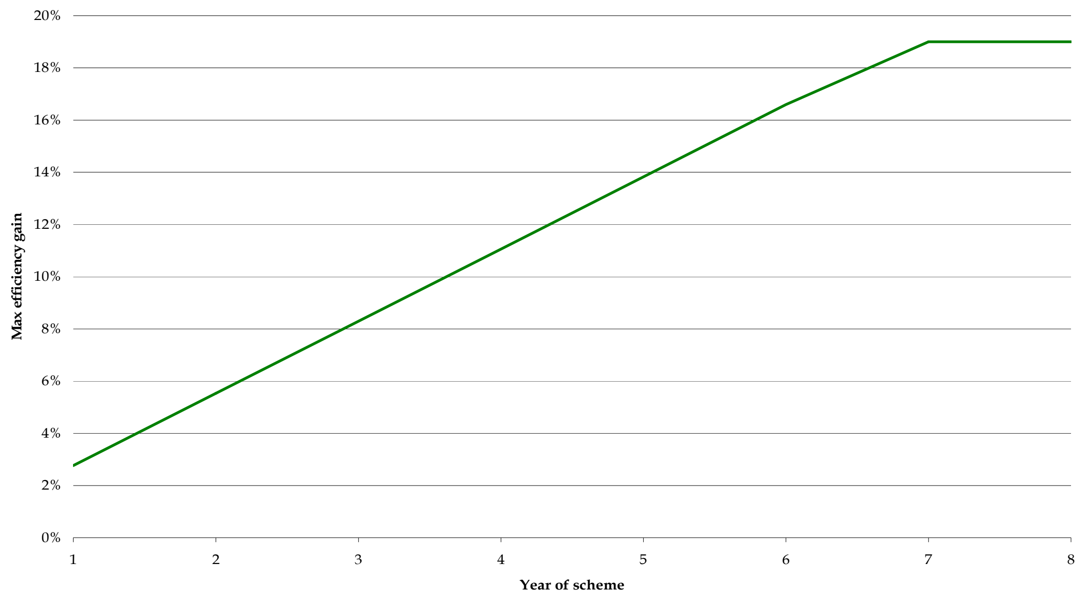
Although costs of each option are unlikely to vary by state, the value of energy savings does vary by state and regions within states. Hence, the level of uptake for each option could vary by region, depending on the relative value of energy savings.

However, the level of uptake in the model is also assumed to be affected by other factors. First, there is an absolute limit on the number of households or business premises that could adopt each energy efficient option. In the case of the residential sector, the limit is set either by data on the number of households that already have the energy efficient option (for example, the number of homes with roof and wall insulation, the number of homes with front end clothes washers) or an assumed maximum penetration rate (typically applied in the commercial and industrial sectors).

The second limit is the assumption that other factor may limit the annual uptake of new appliances even of appliances that are economic. These factors include the natural turnover rates of appliances and the inertia often exhibited for the uptake of new technologies.

To illustrate, we use the example of front end clothes washers. Based on data provided by the ABS, about 19% of homes already have a front end loader. Thus, the maximum number of homes that could change to a front end loader was limited to 81%. Clothes washers have a life of around 15 years, so in the model it would take this long to replace the entire stock of top loaders. On top of this, there is an annual uptake constraint expressed as a percent of total possible energy savings (that is, in each year only the number of washing machines that could achieve the specified proportion of maximum potential efficiency gain are adopted. For front end loaders, this constraint on uptake is illustrated in the following chart.

Figure 4-1: Uptake constraints for front end loaders.



For the residential sector, the potential energy savings is also affected by the interactions between options. Thus, for example, if as part of the energy efficiency obligation scheme, a number of homes install wall insulation, which leads to less energy used in space conditioning. This means that a household that then also installs a more efficient air-conditioner would experience less energy savings from this more efficient appliance than would have occurred if it had not installed the wall insulation. The model uses an iterative process to capture these interactions.

Sources for the data behind the assumptions on energy efficiency potential include:

- Australian Bureau of Statistics: Household numbers (*Catalogue Number 4102*) and appliance uptake proportions (*Catalogue Number 4602: Environmental Issues: Energy Use and Conservation*).
- National Framework for Energy Efficiency (2003), *Background Report: Assessment of Demand-Side Energy Efficiency Improvement Potential and Costs*.
- George Wilkenfield and Associates. Various Regulatory Impact Statements reports to the National Framework Energy Efficiency on various proposals for minimum energy performance standards.
- EMET (2004), *Energy Efficiency Improvement in the Residential Sector*, report to Sustainable Energy Authority of Victoria.
- I. McNichol (2003), *Residential Sector Energy Efficiency Potential*, Sustainable Energy Authority of Victoria.
- Union of Electricity Industries (2004), *Electricity for More Efficiency: Electric Technologies and their Energy Savings Potential*, June, Brussels.

- Energy Rating Agency, which contains data on the energy use of appliances with different star ratings.
- Choice (2007).
- Beacon (2009).

4.3.2 Commercial sector

For the commercial sector, the model captured the following energy efficiency options:

- *Improved shell on commercial buildings*. The average office building is rated as 2 stars for energy performance. This options models the cost and energy saving from an increase in the star rating on new buildings up to 4 stars in 2020.
- *Retail refrigeration efficiency improvement*. This option involved increasing the rate of adoption or replacement of refrigeration facilities to world's best practise models.
- *Retail lighting efficiency*. This option involved the replacement of existing lighting in commercial buildings with the most efficient lighting available.
- *Retail air-conditioning upgrades*. This option comprised upgrades to air-conditioning systems (for both heating and cooling) on retail premises to higher efficiency systems.
- *Hospital lights replacement*. This option involved the replacement of existing lighting systems with more efficient alternatives.
- *Hospital air-conditioning replacement*. This option involves the replacement of existing hospital heating and cooling systems with a more efficient alternative.
- *Hospital wall insulation replacement*. This option involved upgrading wall and ceiling insulation in hospital.
- *Other commercial building lighting upgrade*. This option involved the adoption of high efficiency lighting in other commercial buildings.
- *Other commercial building air-conditioning upgrade.* This option involved the adoption of high efficiency air-conditioning systems in other commercial buildings.

Assumptions used for each program are detailed in Table 4-2. Sources used to derive these assumptions included:

- EMET (2004), *The Impact of Commercial and Residential Sectors' EEI's on Electricity Demand*, report to Sustainable Energy Authority of Victoria.
- EMET (2004), *Energy Efficiency Improvement in the Commercial Sub-Sectors*, report for Sustainable Energy Authority of Victoria, February.
- Australian Bureau of Statistics (various catalogues dealing with number of business enterprises).

Table 4-2: Assumptions for key energy efficiency options for commercial sector

	Max efficiency gain	Max penetration rate	Additional cost per unit, $	Phase in, years	Annual stock turn
Building shell	10%	15%		70	1%
Retail refrigeration	33%	50%	5,000	20	5%
Retail lighting	15%	50%	10	12	8%
Retail space conditioning	15%	50%	8,000	20	5%
Hospital lighting	10%	50%	120	12	8%
Hospital space conditioning	10%	50%	200,000	12	8%
Hospital insulation	10%	50%	600,000	20	8%
Other lighting	15%	50%	120	12	8%
Other space conditioning	15%	50%	180,000	12	8%

Source: MMA analysis using data sources listed in the text.

4.3.3 Primary and secondary industry

The industrial, mining and agriculture sectors consume the largest proportion of energy used. These sectors account for 60% of total energy use in stationary energy activities.

The energy efficiency potential in these sectors was modelled as a function of the level of energy improvement rather than on specified programs. This is because of the large range of options available to reduce emissions and the lack of data on the potential improvement and the cost of each option, which can vary considerable by sub sectors within industry and by plants within sub sectors.

The assumptions used are outlined in Table 4-3.

Table 4-3: Assumptions for key energy efficiency options for primary and secondary industries

	Agriculture	Mining	Wood, paper and printing	Petroleum, coal, chemicals	Non-metallic mineral products	Metals	Other
Maximum uptake	25%	5%	25%	25%	15%	30%	25%
Due to:							
Machinery/equipment	50%	60%	40%	40%	40%	10%	40%
Process heat	0%	0%	50%	50%	30%	80%	50%
Engines/motors	50%	40%	10%	10%	30%	10%	10%
Max efficiency gain	10%	5%	10%	10%	10%	10%	10%
Assume phase in period	15	15	15	15	15	15	15
Parameters for calculating cost as a function of the efficiency improvement[1]							
a	3,798	17,564	8,892	11,470	3,005	38,000	3,329
b	1.63	1.61	1.92	1.91	1.63	0.89	0.98

Note: (1) Costs are specified in the form y=ax^b, where y is total cost and x is energy efficiency improvement in PJ. Source: MMA analysis based on NFEE (2004), *Energy Efficiency Improvement Potential Case Studies – Industrial Sector*, Canberra, March.

4.4 Modelling Process

The modelling process to determine the future price path of certificates and the uptake of energy efficiency options was as follows:

- The life time costs of a range of energy efficient technology options were estimated.
- The energy costs avoided for each option considered were estimated. Energy costs avoided were adjusted according to the usage profile of the energy efficient option.
- Payback periods for each option were also calculated. Options with payback period of less than two-years were assumed to be taken up in the reference scenario without the need for incentives under the energy efficiency obligation scheme.
- For each option with payback periods greater than two years, the certificate values over the remaining term of the energy efficiency obligation scheme required to achieve a required payback period for adoption were calculated.
- The energy efficiency options were ordered by ascending certificate price to achieve the required payback period. The interim targets plus demand for banked credits in each year determined which options were adopted in a particular year.
- The certificate price was increased until sufficient options were adopted to meet the cumulative target under the energy efficiency obligation scheme.
- The options adopted in each year were determined by the economic viability subject to the certificate price path, certificate creation and surrender constraints.
- The resulting energy reduction levels were then input into wholesale electricity market and gas market models to determine the changes to retail prices that in turn impact the certificate prices.
- The process was repeated until stable outcomes result.

The model considers the time from when the option is adopted to the end of 2020 for certificate revenue but only considers energy (electricity) costs avoided beyond 2020 if the economic life of the option goes beyond 2020. Options with a payback period of less than 2 years were deemed to be adopted anyway even without the initiative (and not additional, so will not be rewarded under the scheme). The model optimises to get the least cost option to meet the cumulative target over the program period.

The certificate price is also determined by this process. Certificate price was used as an additional revenue stream. An option was assumed to be adopted if the certificate price was sufficient for an energy savings option to have a payback period of 3 years or less for residential customers and a payback period from 2 to 5 years for commercial and industrial customers[5]. The certificate price was increased until such times as sufficient certificates were created to meet the target. Each option was assumed to receive an upfront deemed amount of certificates according to the projected energy savings over the lifetime of the option.

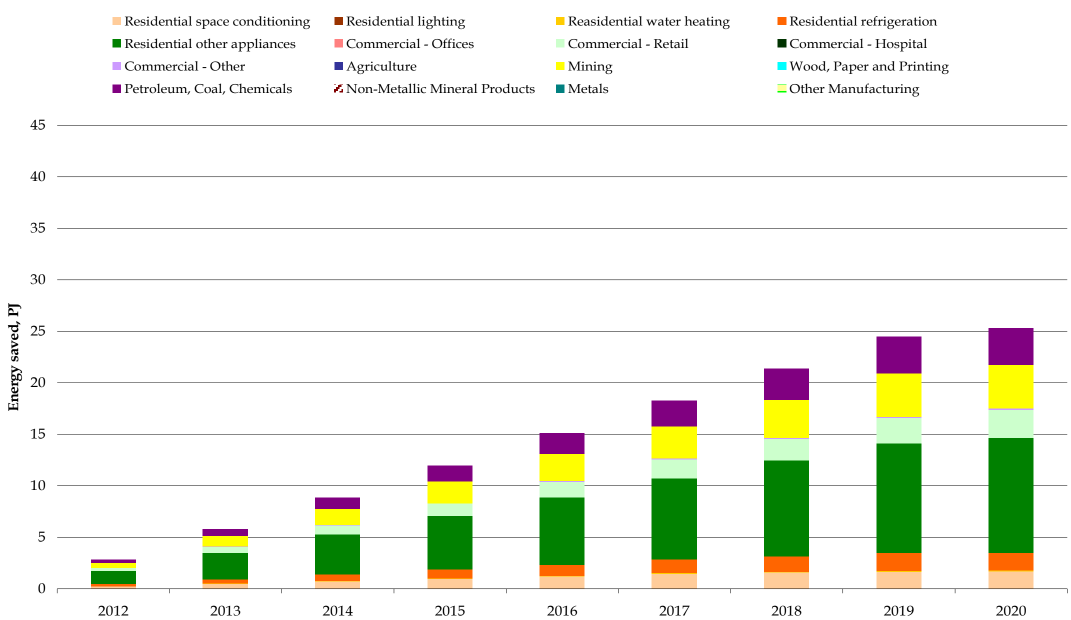
4.5 Uptake of Energy Efficiency

Energy efficiency uptake was confined mainly to the residential and industrial sectors. In the residential sector, the savings in energy use was predicted to mainly come from uptake of more efficient white good and electronic equipment, and from more efficient air-conditioning. In the industrial sector, the savings mainly came from the mining and chemical sectors.

Energy use for heating and cooling is reduced the most under the scheme. For residences that adopt energy efficient practises, energy use for heating and cooling is reduced by 6% in the low target case and up to 20% with a high target. Energy use in appliances is reduced by 12% to 15%. For other residential activities, energy use is reduced by less than 7%.

The commercial sector is predicted to benefit least from the scheme, with energy use reduced by less than 1% with a low target and around 3% with a high target. Most of the energy savings are predicted to occur in the retail sector.

Figure 4-2: Energy saved by activity, CPRS -5 with a low target



5 For large industrial customers, it was assumed that all energy savings options with a payback period of less than 2 years with the energy efficiency obligation scheme would be adopted under the current EEO measure.

Figure 4-3: Energy saved by activity, CPRS -5 with a medium target

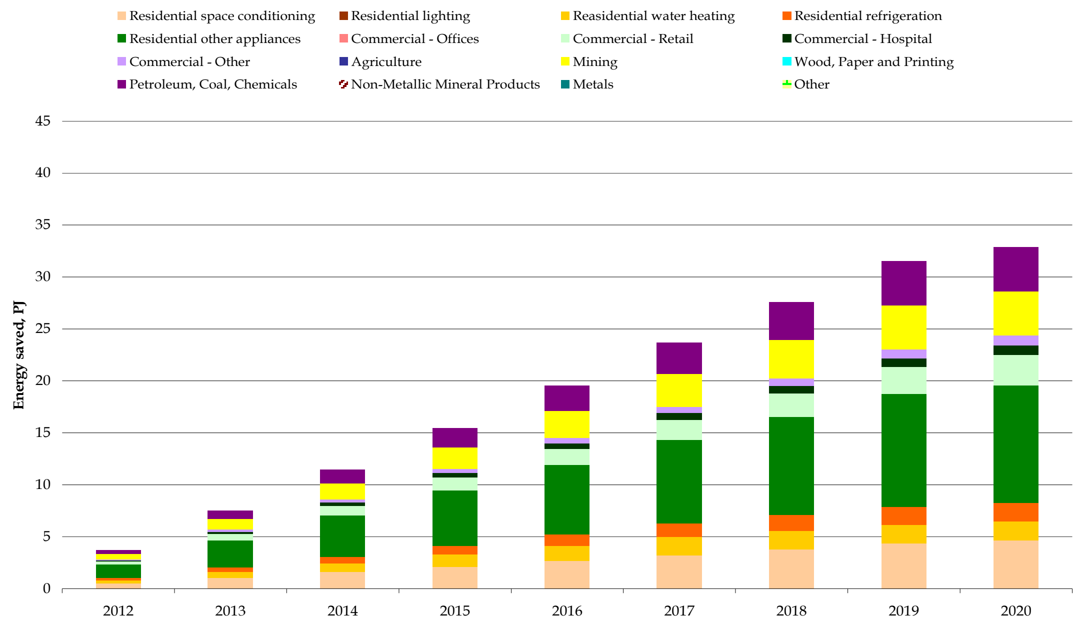
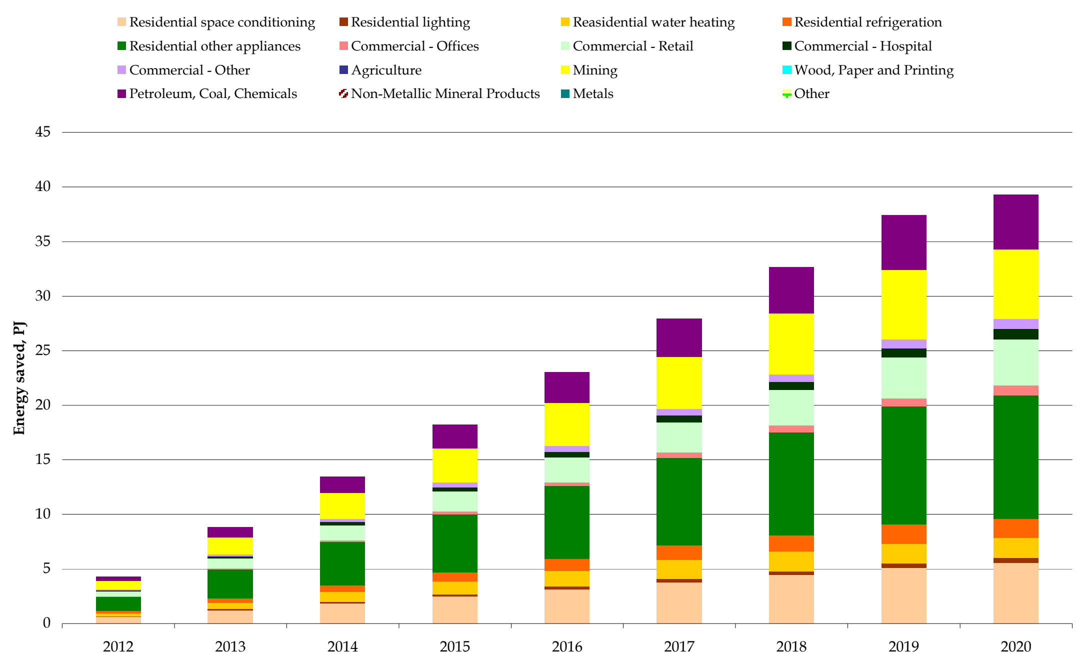


Figure 4-4: Energy saved by activity, CPRS -5 with a high target



Source: MMA analysis.

4.6 Compliance Costs

Certificate prices range from between \$14/MWh equivalents to \$18/MWh equivalents for the low target under the CPRS -5 and from \$25/MWh equivalents to \$33/MWh equivalents for the high target under the CPRS -5. Permit prices are significantly higher under the higher target of the CPRS -15 scenario due to the higher target imposed, which outweighs the dampening effect on price of the higher values on energy savings.

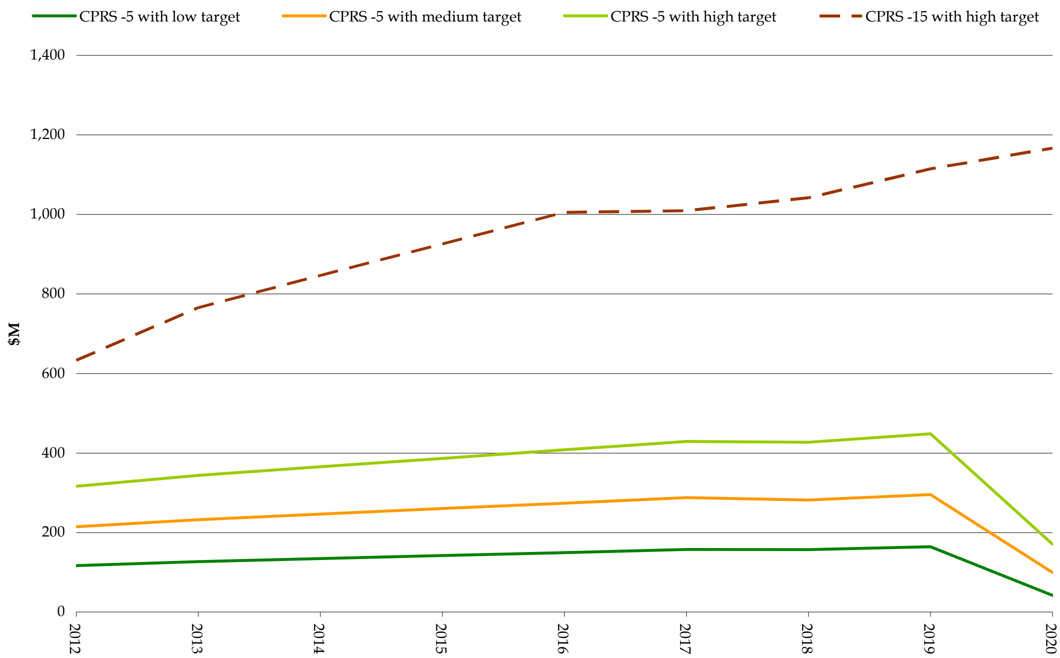
Compliance costs, which mainly cover the cost of the certificates and administration costs are shown in Figure 4-6. The present value of compliance costs ranges from $800 million for the CPRS -5 scenario with a low target to $2,200 million for the CPRS -5 scenario with a high target.

The estimates of compliance costs does not take into account the savings in costs from replacing the state based energy efficiency schemes operating in Victoria, New South Wales and South Australia.

Figure 4-5: Certificate prices

Source: MMA analysis.

Figure 4-6: Compliance costs



5 BENEFITS AND COSTS

5.1 Benefits to Energy Users

Energy savings for the low and high carbon cases are shown in the following charts, assuming no limits on energy savings under the scheme.

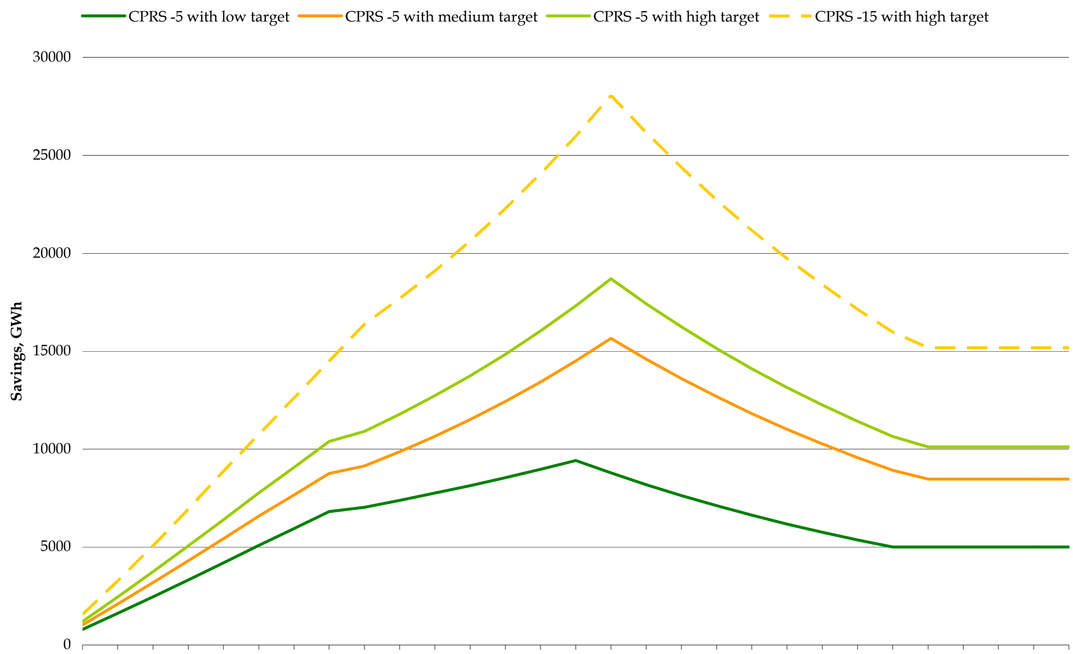
By 2020, the potential savings were estimated to be around 7,900 GWh with a low target, 10,800 GWh for a medium target and around 11,500 GWh for a high target, and around 19,000 GWh for a high target and higher carbon prices. Potential gas savings were estimated to be around 24 PJ in medium target scenario, 30 PJ in the high target scenario and 69 PJ with high carbon prices and high savings target (no gas target applies in the low target scenario).

Savings increased after 2020 due to normal increased usage of appliances with income growth and the fact that energy efficiency options adopted under the scheme in a given year result in energy savings over an effective life beyond the end of the scheme but the corresponding certificates for energy savings over the options life are accrued in the year of installation. Eventually, energy savings begin to diminish as appliances are replaced, with the assumption that up to 50% of the defunct appliances are replaced with the less efficient model (based on the behavioural assumption that without the scheme the same market failure would influence consumer choice).

Without a higher energy saving target, the potential savings in the high carbon price case could have been lower for two reasons. First, many of the energy efficiency options had improved returns from higher electricity prices under a higher carbon price so they were adopted even without the scheme (had payback period less than 2 years). Second, the level of overall demand was lower as customers responded to lower disposable incomes due to the higher energy prices (i.e. price induced demand response).

The bulk of the savings occurred in the industrial sector, which accounted for about 48% of the savings, mainly due to this sector's high proportion of savings in gas usage. Industrial sector accounted for about a quarter of the electricity savings, but over three-quarters of the savings in gas usage. The residential sector accounted for 44% of energy savings, with this sector contributing the greatest savings in electricity usage with over half of the savings in electricity usage. The commercial sector only accounted for about 8% of the energy savings, with all this being savings in electricity use.

Figure 5-1: Energy savings, electricity, CPRS -5 carbon price

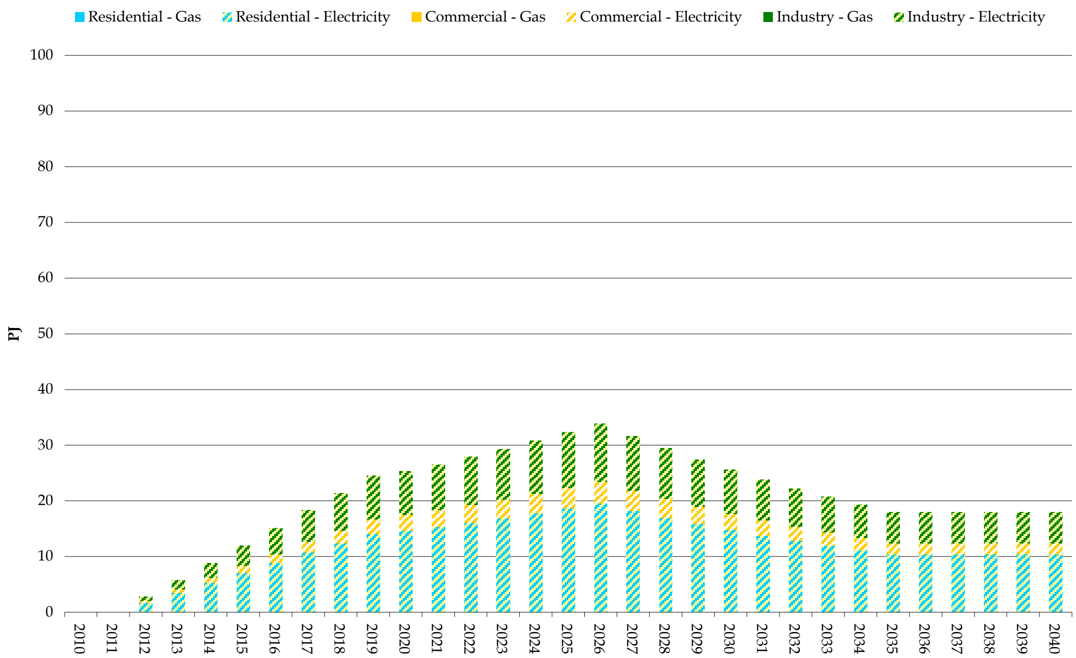


Source: MMA analysis.

Figure 5-2: Energy savings, gas

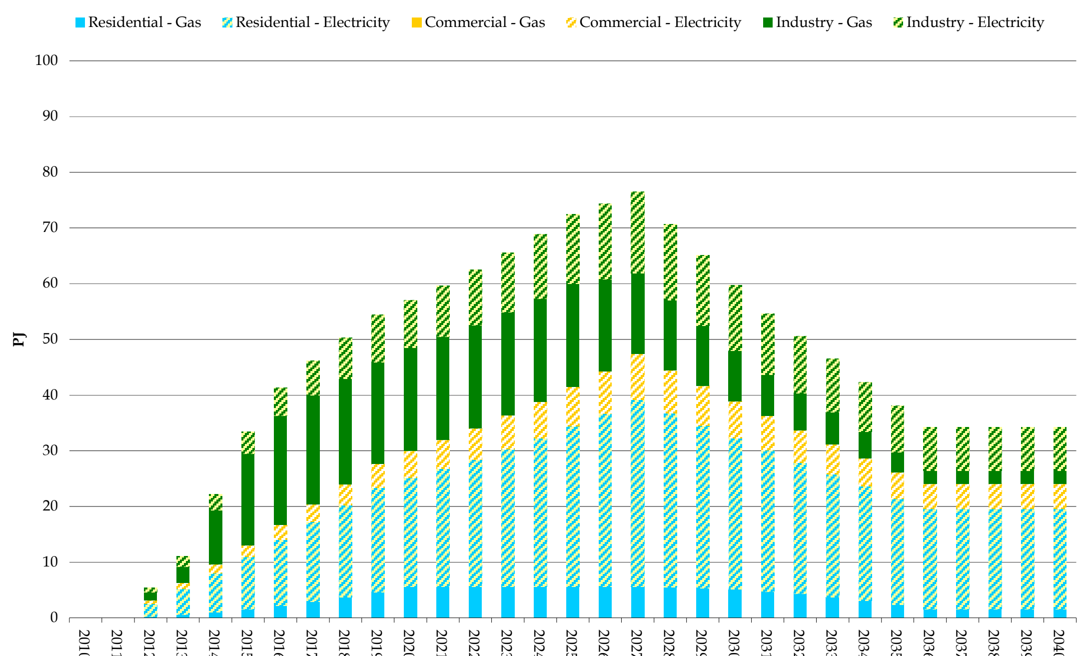
Source: MMA analysis.

Figure 5-3: Energy savings, CPRS -5 with low energy savings target



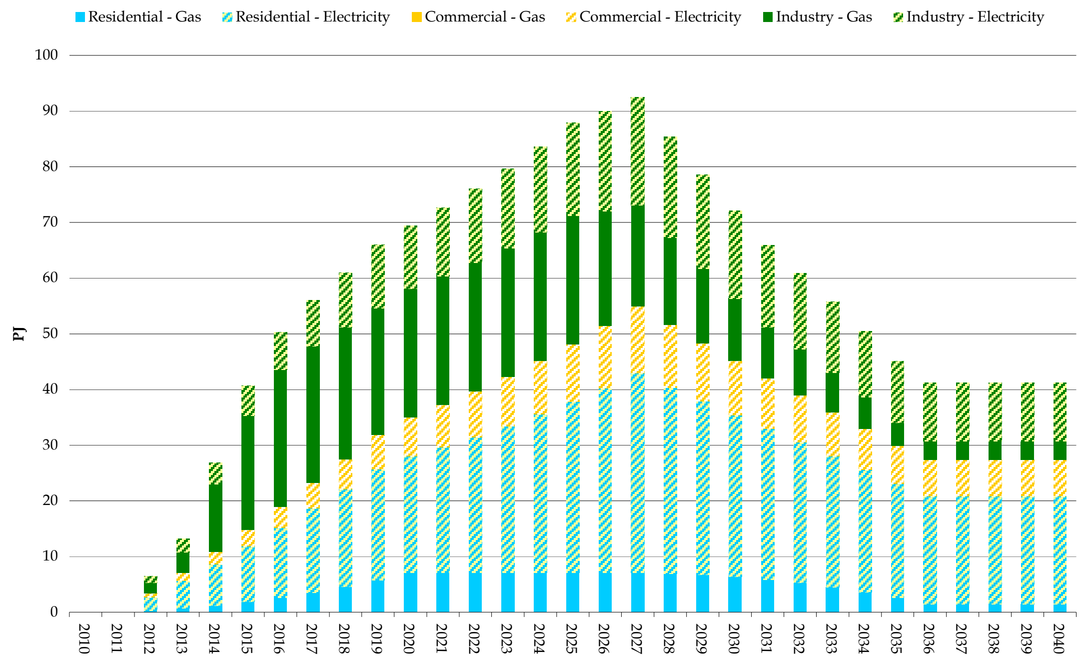
Source: MMA analysis.

Figure 5-4: Energy savings, CPRS -5 with medium energy savings target



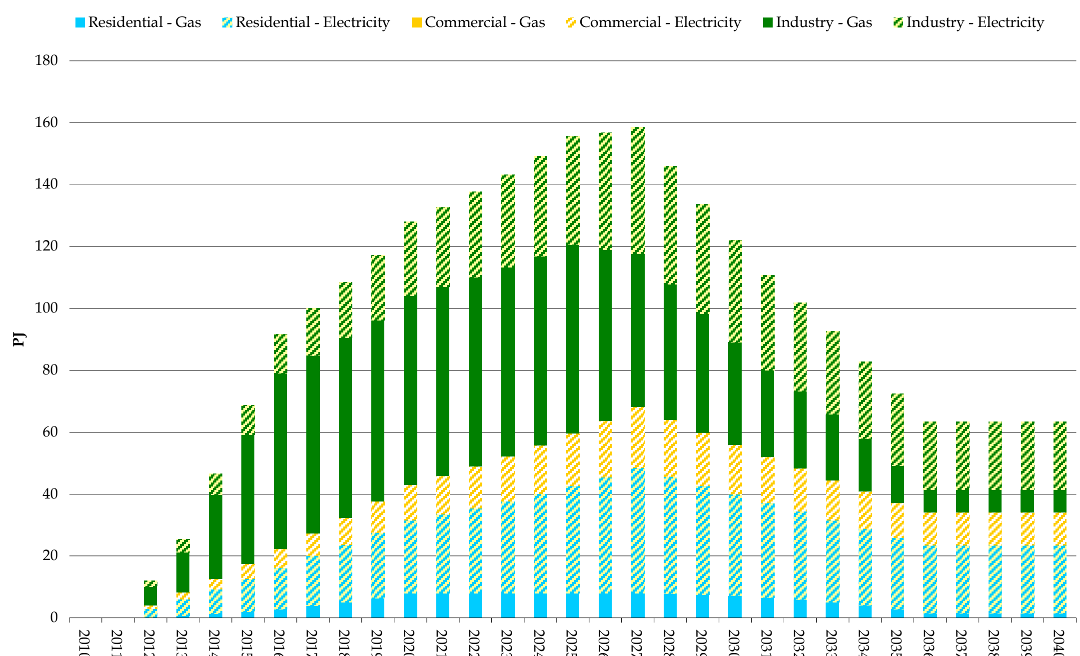
Source: MMA analysis.

Figure 5-5: Energy savings, CPRS -5 with high energy savings target



Source: MMA analysis.

Figure 5-6: Energy savings, CPRS -15 with high energy savings target



Source: MMA analysis.

5.2 Benefits and Costs to the Electricity Markets

Programs that overcome market failures that prevent the uptake of energy efficiency options provide benefits to the energy markets in the form of reduced resources to produce electricity and supply gas. In this study, the following benefits to the energy market from the scheme were estimated:

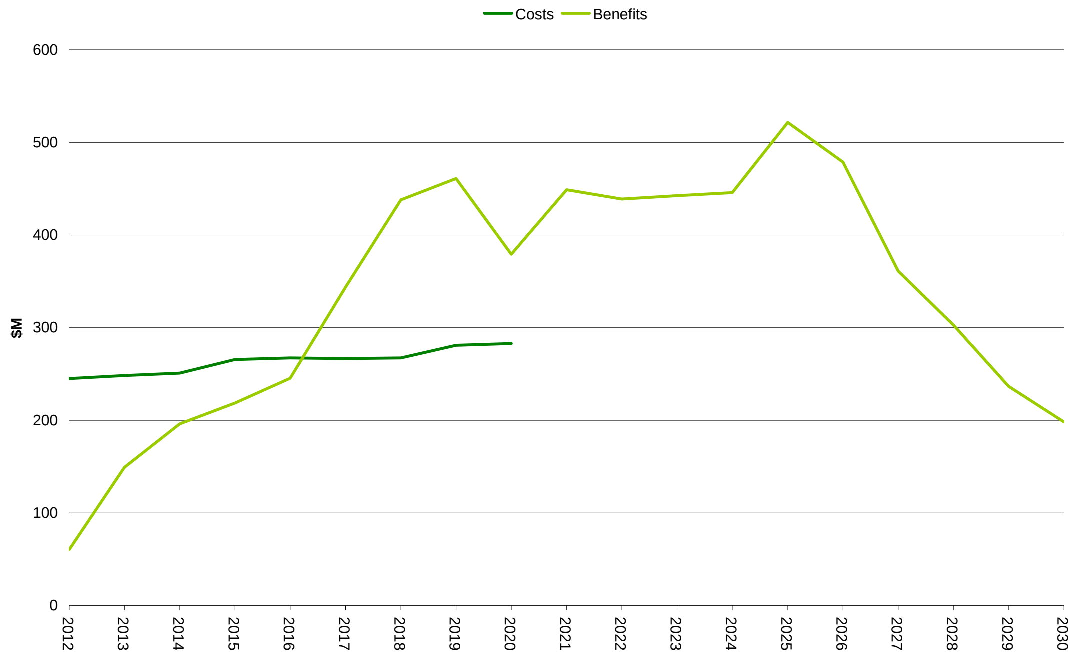
- Reduction in capital costs resulting from deferred entry of new generation plant.
- Reduction in fuel costs from reduced use of coal and gas in electricity generation.
- Reduction in non-fuel variable operating costs.
- Reduction in costs from deferment of construction of interregional interconnects.
- Reduction in gas processing and transmission infrastructure costs.

The benefits from abatement were not included as under an emission trading scheme, an energy efficiency program would compete with other abatement activities.

The cost of energy efficiency was estimated to be equivalent to the additional capital cost from adopting the energy efficiency appliance and process.

The benefits and costs were calculated by comparing costs of electricity generation and gas supply with energy efficiency with costs of electricity generation and gas supply without energy efficiency. In both the reference (without energy efficiency) and energy efficiency obligation scenarios, there is an assumption that emission trading was enforced. So the analysis only compares the benefits of having an energy efficiency program that complements an emission trading scheme.

Figure 5-7: Benefits and costs of the energy efficiency obligation scheme to the electricity markets – CPRS -5 with low energy savings targets



Source: MMA analysis.

The present value of all benefits and costs are shown in the following table. Features of the results are as follows:

- Net benefits from 2012 to 2040 range from \$1.8 billion to \$2.3 billion for the CPRS -5 scenarios, which represents less than 2% of the total cost of energy supply. The benefits are small because of the small targets, the assumption of declining energy savings over the long-term due to as assumption that consumer revert to all patterns of choice and to a limited range of energy efficiency programs being considered.

- Benefits tend to be higher for the higher carbon case. This is in part due to the higher energy efficiency target, but it is also due to the fact that energy efficiency defers the need to invest in expensive low emission generation options, with this expense increasing the higher the carbon price.

- For a given carbon price trajectory, the benefits peak and then decrease as the energy savings diminish. This result suggests that at some point there are diminishing returns to adopting further energy efficiency appliances and practises, as the marginal cost of further adoption exceed the marginal benefits. With the CPRS -5 case, the net benefit is lower for the high energy savings target than for the medium target. This is because the high certificate prices makes it economic to purchase appliances and measures with minimal energy savings potential over the life of the appliance.

Benefits increase beyond 2020 as the energy efficiency savings defer the need for new low emission plant.

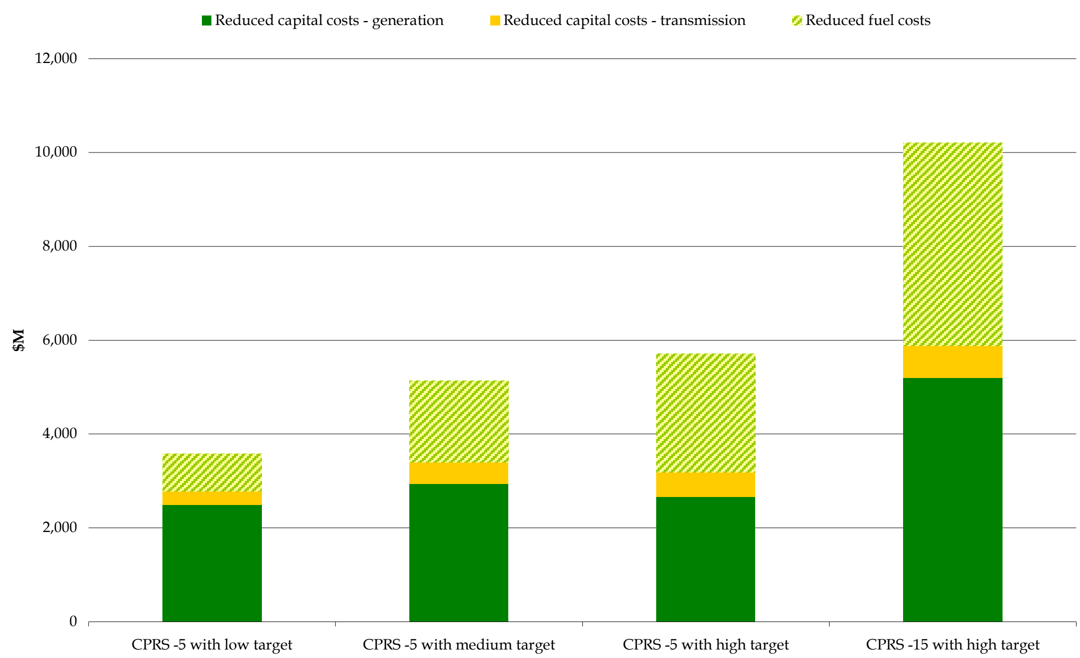
Table 5-1: Present value of benefits and costs to the electricity markets, $M

	CPRS – 5 scenario			CPRS -15 high target
	Low target	Medium target	High target	
Costs	1,586	2,819	3,959	4,652
Benefits	3,581	5,139	5,711	10,205
Net Benefit	1,995	2,320	1,752	5,553

Present values calculated for the period 2012 to 2040 using a discount rate of 6%. Source: MMA analysis.

Reductions in capital costs in generation are the main form of benefit, comprising over 50% of the benefits. Savings in fuel costs contribute the next largest benefit. Savings in transmission costs comprise less than 10% of the benefits.

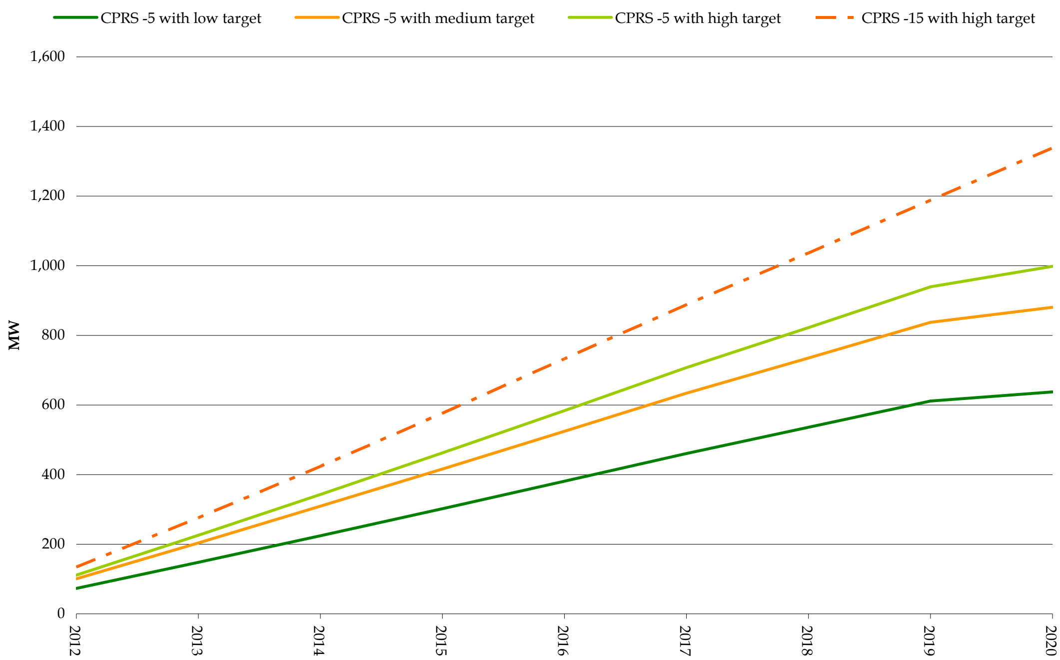
Figure 5-8: Breakdown of benefits for the electricity market



Note: each bar represents the present value of the savings in costs over the period from 2012 to 2020, calculated using a 6% discount rate. Source: MMA analysis.

Lower investment in generation is driven by the reduction in demand. Peak demand in 2020 is reduced by around 600 MW to 1,300 MW depending on the level of energy savings. The reduction in peak demand is likely to be maintained until after 2030. The reduction in peak demand reduces the need for new peaking plant.

Figure 5-9: Reduction in peak demand due to the hypothetical energy efficiency obligation scheme



5.3 Benefits and Costs to the Gas Markets

Net benefits are also obtained for the gas market as a result of the energy efficiency obligation scheme. The net benefits are smaller than for the electricity market, with net benefits less than $360 million when the reference is the CPRS -5 scenario and around $1,200 million when the reference is the CPRS -15 scenario.

The benefits come largely from decreased cost in transmission investment, which comprises over 90% of the savings. Production costs are also lower, but these comprise only 10% of the savings.

Table 5-2: Present value of benefits and costs to the gas markets, $M

	CPRS – 5 scenario			CPRS -15 high target
	Low target	Medium target	High target	
Costs	0	258	391	728
Benefits	0	604	751	1,835
Net Benefit	0	346	360	1,107

Present values calculated for the period 2012 to 2040 using a discount rate of 6%. Source: MMA analysis.

5.4 Net Benefits

Net benefits for the energy markets are shown in Table 5-2. The benefits are estimated to be in the range of $2.0 billion to $2.6 billion under a CPRS -5 scenario and around $7.2 billion for the CPRS -15 scenario.

Table 5-3: Present value of benefits and costs to the energy markets, $M

	CPRS – 5 scenario			CPRS -15 high target
	Low target	Medium target	High target	
Benefits	1,586	3,077	4,350	5,380
Costs	3,581	5,743	6,462	12,040
Net Benefit	1,995	2,666	2,112	6,660

Present values calculated for the period 2012 to 2040 using a discount rate of 6%. Source: MMA analysis.

6 OTHER IMPACTS

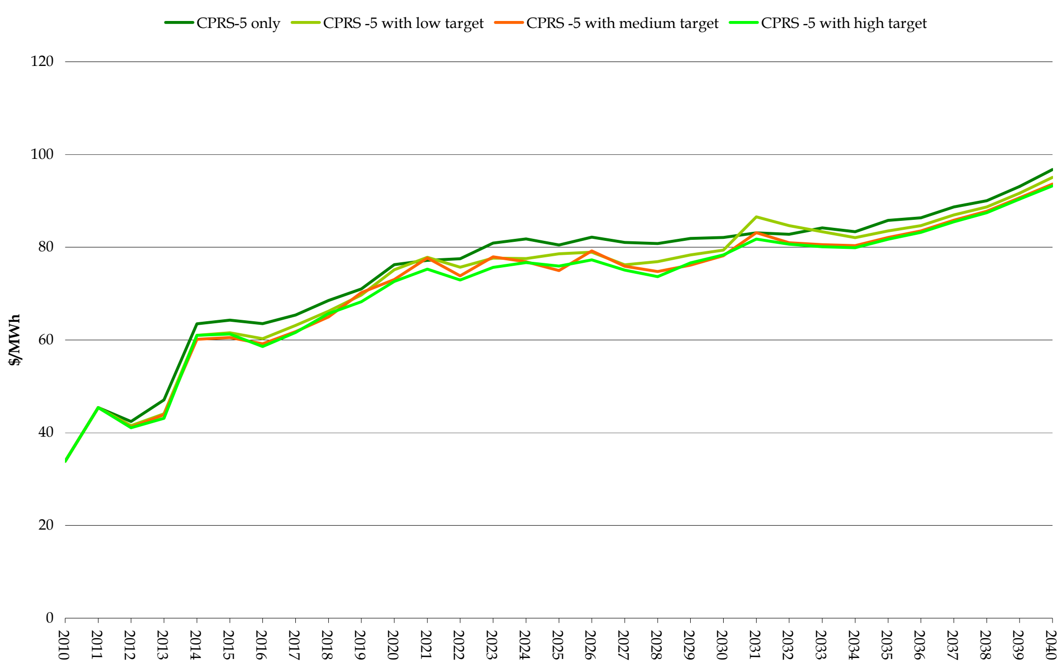
6.1 Electricity Prices

6.1.1 Wholesale prices

Wholesale electricity prices are generally lower, although there are a few years in which they are higher under an energy efficiency obligation scheme. This occurs because the lower energy demand defers entry of some new generation which are of low cost relative to current generation. The decrease in price in the period to 2020 is exacerbated by the fact that there is a fixed target for new renewable generation under the LRET scheme, which tends to limit the amount of new generation capacity that can be deferred and therefore creates a short term capacity surplus.

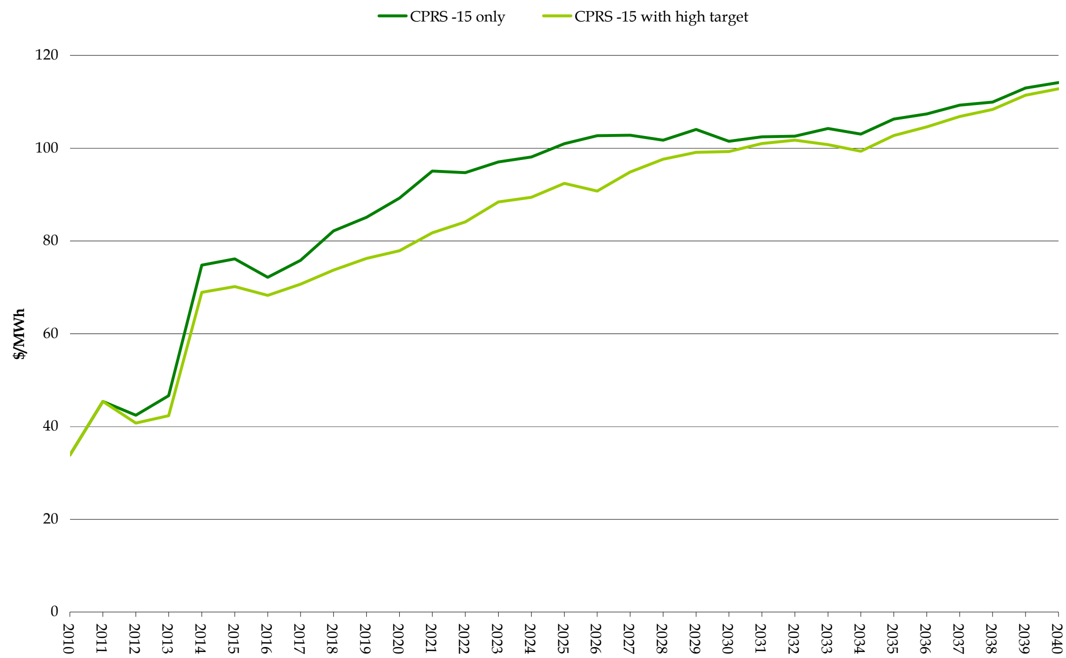
Over the long-term, the greater the energy savings target the lower the prices. The greater the energy savings target, either the more retirement of less efficient plant or the greater the deferment of new expensive low emission plant. Greater energy savings reduces operating costs, including the costs of purchasing greenhouse emission permits.

Figure 6-1: Wholesale prices in the NEM, CPRS -5 scenarios



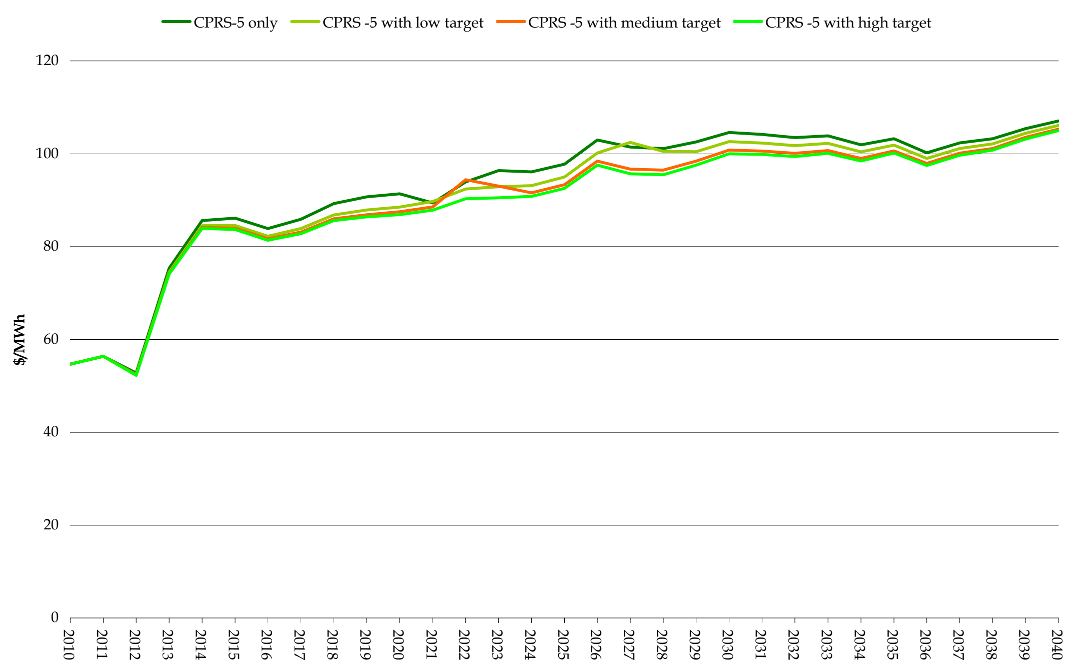
Source: MMA analysis.

Figure 6-2: Wholesale prices in NEM, CPRS -15 scenarios



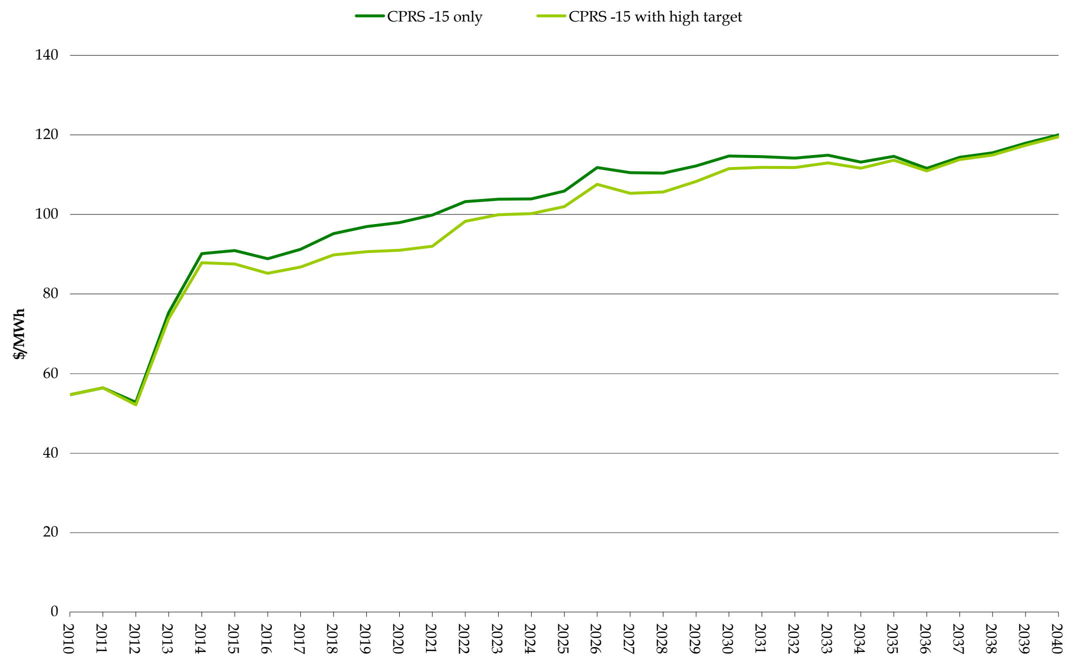
Source: MMA analysis.

Figure 6-3: Wholesale prices in the SWIS, CPRS -5 scenarios



Source: MMA analysis.

Figure 6-4: Wholesale prices in the SWIS, CPRS -15 scenarios



Source: MMA analysis.

6.1.2 Retail prices

Retail price impacts are a function of a number of factors:

- The change in wholesale prices. As discussed above, there is a decrease in wholesale prices as a result of the energy efficiency obligations scheme.
- The cost of purchasing the certificates, with this cost spread over all liable customers. This cost is equal to the certificate price times the target (rate of adoption of energy efficiency programs under the scheme). To determine impact on retail prices, it is assumed that this cost is spread over all residential, commercial and liable industrial customers.
- The cost of administering the scheme, which is assumed to be spread equally across all customers.
- The change in cost of renewable energy certificates (REC) under the LRET scheme. Because there are changes to the wholesale electricity price, then there will be changes in the certificate price required to encourage enough renewable generation to meet the target. Thus, as wholesale prices are predicted to decrease, then a commensurate increase in REC prices is predicted.

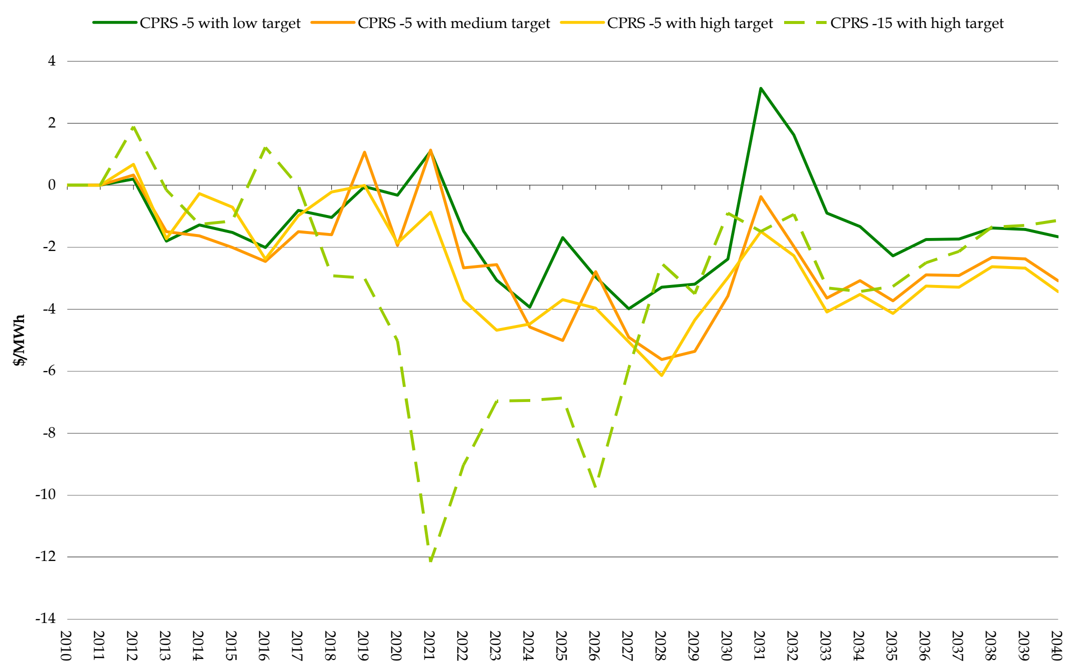
Retail prices, even after the imposts are added, are expected to be lower. The reduction in wholesale price is expected to outweigh the impact of compliance costs and the increase in REC prices. Over the period to 2030, the reduction in retail prices is predicted to average around 1% for the low and medium targets and around 2% for the high target. For the CPRS -15 scenario with a high target, the average decrease is predicted to be around 2%.

Table 6-1: Impact on retail prices, NSW

		CPRS – 5, medium target			CPRS -15, high target		
		2012	2020	2030	2012	2020	2030
Average Delivered Price							
Industrial	$/MWh	71	124	133	72	132	157
Commercial	$/MWh	124	202	216	125	210	240
Residential	$/MWh	153	246	262	155	254	286
Change from CPRS only							
Industrial	$/MWh	0	-2	-3	2	-10	-1
Commercial	$/MWh	0	-2	-3	2	-10	-1
Residential	$/MWh	0	-2	-4	2	-10	-1
Change from CPRS only							
Industrial	%	0.5%	-1.3%	-2.5%	2.6%	-6.9%	-0.6%
Commercial	%	0.3%	-0.8%	-1.6%	1.5%	-4.5%	-0.4%
Residential	%	0.2%	-0.7%	-1.3%	1.3%	-3.8%	-0.4%

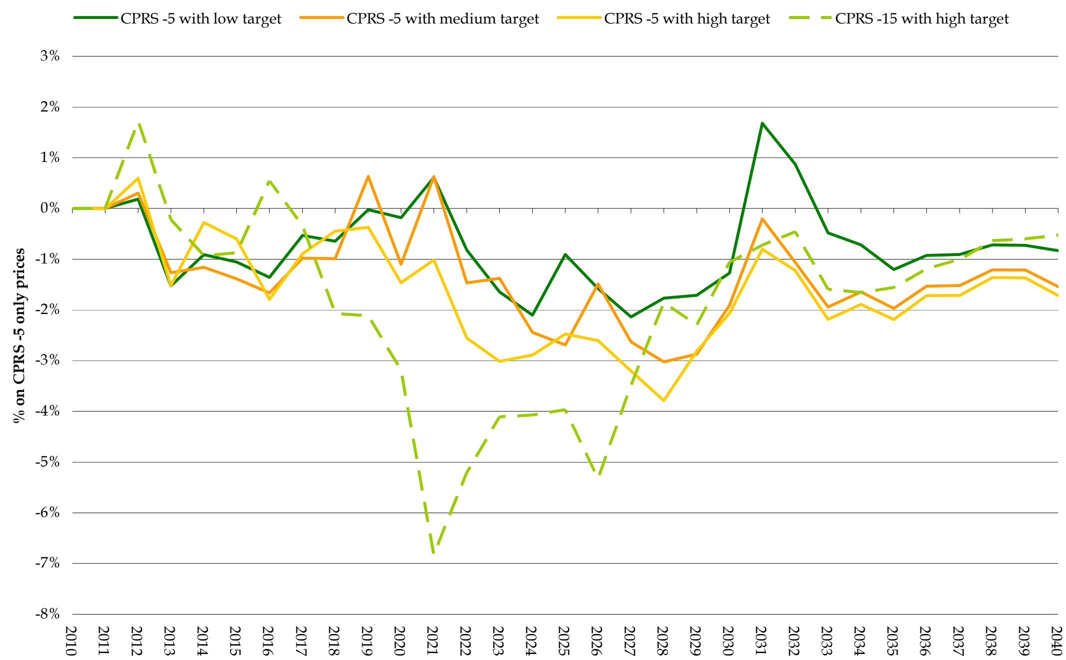
Source: MMA analysis.

Figure 6-5: Change in average retail prices across all customer classes, Australia



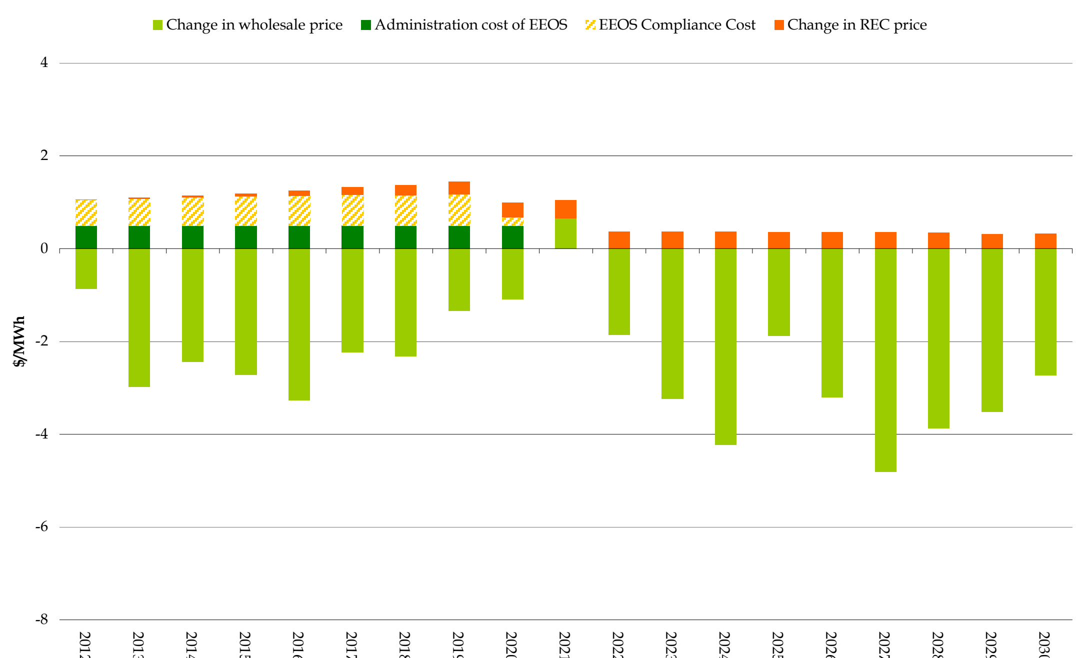
Source: MMA analysis.

Figure 6-6: Percentage change in average retail prices across all customer classes, Australia



Source: MMA analysis.

Figure 6-7: Composition of change in retail prices, CPRS -5 with low target



Source: MMA analysis. Note: each data point represent either an added impost or change in price relative to the CPRS only case due to the energy efficiency obligation scheme. A positive number implies an added cost due to the scheme.

Figure 6-8: Composition of change in retail prices, CPRS -5 with medium target

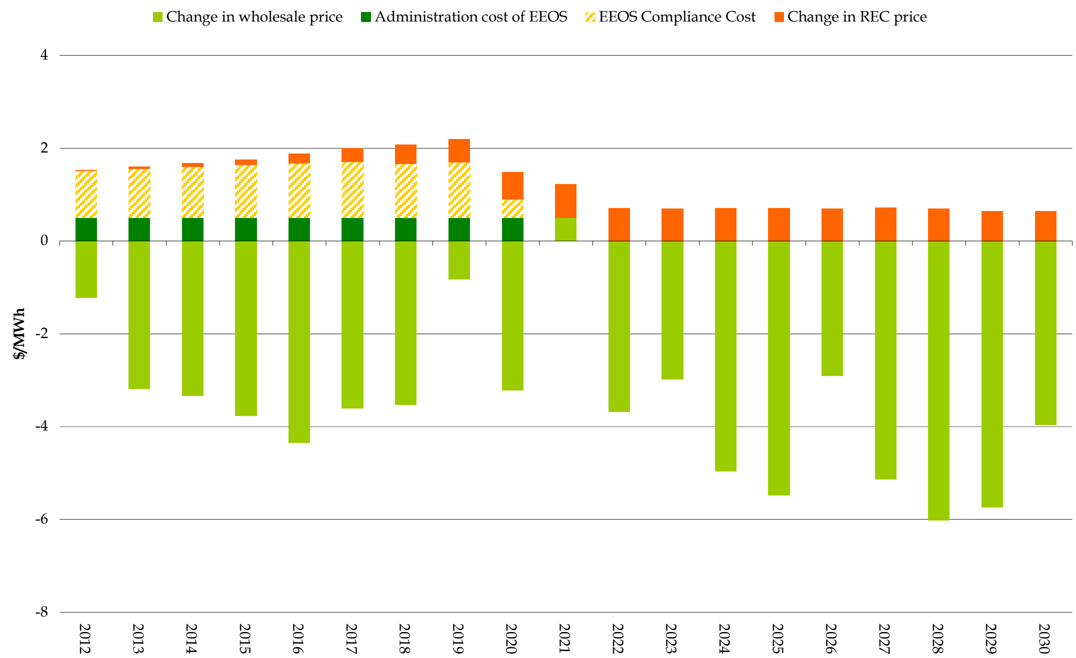
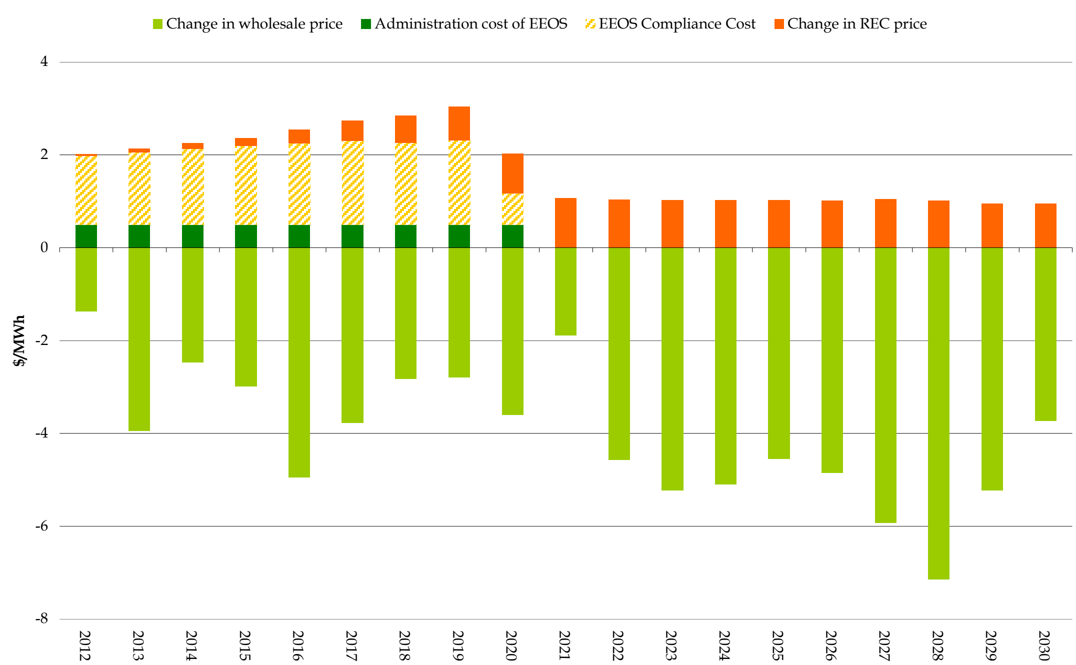
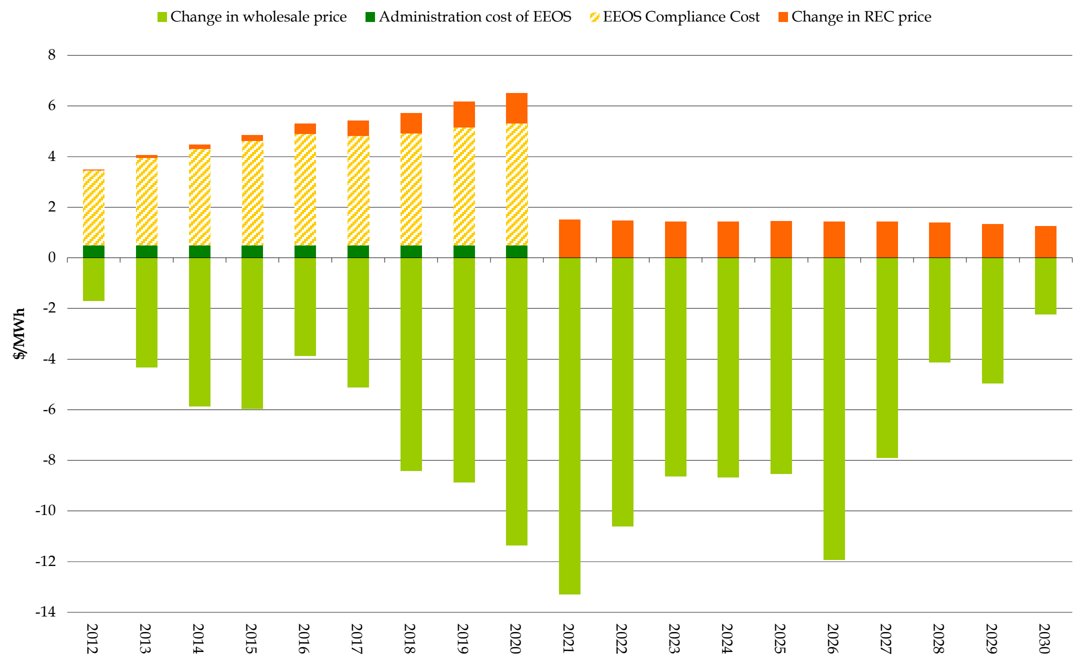


Figure 6-9: Composition of change in retail prices, CPRS -5 with high target



Source: MMA analysis. Note: each data point represent either an added impost or change in price relative to the CPRS only case due to the energy efficiency obligation scheme. A positive number implies an added cost due to the scheme.

Figure 6-10: Composition of change in retail prices, CPRS -15 with high target



Source: MMA analysis. Note: each data point represent either an added impost or change in price relative to the CPRS only case due to the energy efficiency obligation scheme. A positive number implies an added cost due to the scheme.

6.1.3 Expenditure on electricity - households

Household expenditure on electricity falls as a result of the scheme. Both the reduction in energy demand and the fall in retail prices results in expenditure dropping by an average of $1/week to $2/week in the period to 2020 and between $2/week and $5/week in the period from 2020 to 2030.

Table 6-2: Reduction in expenditure on electricity by households, $/week

	2012-2020	2021-2030
CPRS -5 with low target	1.06	2.16
CPRS -5 with medium target	1.39	3.39
CPRS -5 with high target	1.41	3.64
CPRS -15 with high target	1.58	4.69

Note: reductions in expenditure calculated assuming energy savings in the residential sector are spread across all households. Source: MMA analysis.

When the energy savings are spread across all households, the average reduction in expenditure on electricity in 2020 under a CPRS -5 scenario is $1.67/week with a low target to $2.56/week for a high target. Under a CPRS 15 scenario, the average savings in 2020 from a high energy efficiency target when spread across all households is around $3.46/week. For households that implement energy savings measures, the reduction in expenditure is greater, with households adopting 2 energy efficient options saving around $4.60/week to $5.70/week in 2020. These savings have to be compared to the additional cost of purchasing the energy efficient appliance.

6.1.4 Expenditure on electricity - businesses

Businesses also experience a reduction in costs of energy purchases. The reduction is due to the reduction in retail prices and for those businesses adopting energy efficient processes and appliances, through a reduction in the use of energy. This savings has to be matched against the cost of purchasing and operating the energy efficient process.

Considering only the impact of the reduction in retail prices, the savings range from $2/week to $3/week for a small business, from $200/week to $450/week for a medium size business and $1,300/week to $3,000 per week for a large business. The savings are greater for business adopting an energy efficient practise.

Table 6-3: Reduction in expenditure on electricity by businesses, $/week

	Small	Medium	Large
CPRS -5 with low target	2	204	1,359
CPRS -5 with medium target	2	287	1,912
CPRS -5 with high target	2	288	1,923
CPRS -15 with high target	3	456	3,041

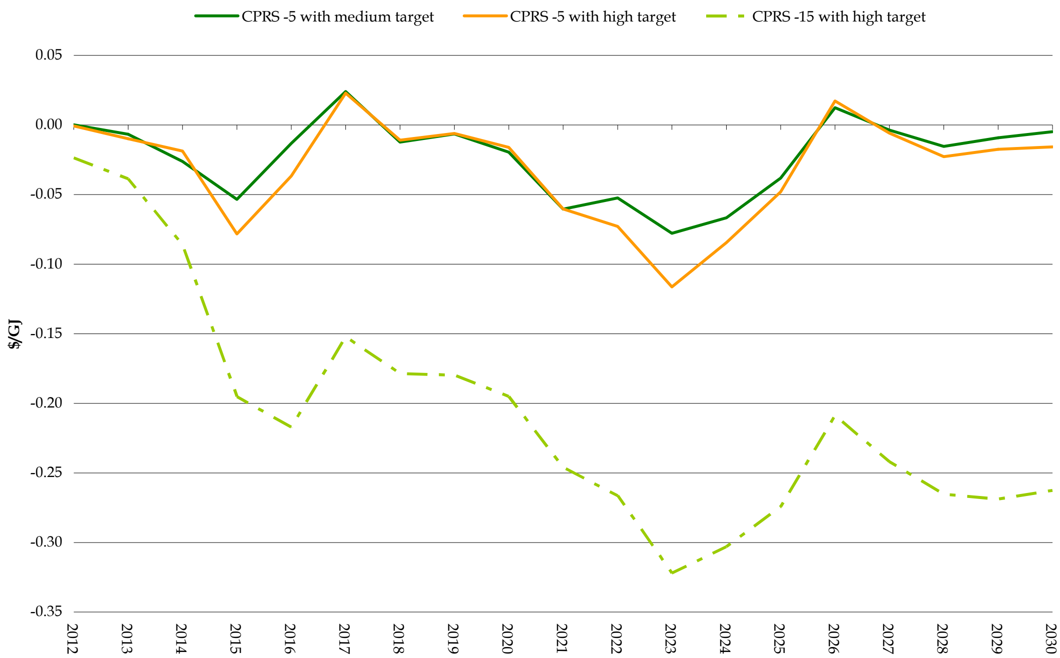
Note: Small business is defined as those consuming 40 MWh per annum, medium sized business as those consuming 6,000 MWh per annum and a large business as those consuming 40,000 MWh per annum. Source: MMA analysis.

6.2 Gas Prices

Gas price impacts are complicated. Wholesale gas prices are expected to reduce by less than $0.10/GJ with an energy efficiency obligation under a CPRS -5 carbon price and by less than $0.30/GJ with an energy efficiency obligation under a CPRS -15 carbon price. However, in the period from 2012 to 2020, retail prices for gas are higher as the decrease in wholesale price does not compensate for the cost of funding the certificates. For the targets under the CPRS -5 scenario, prices in the period to 2020 are on average higher by as much as $0.18/GJ with a medium target and $0.28/GJ for a high target. This represents an increase of around 1% and 1.5% respectively. For the high target under the CPRS -15 scenario, prices in the period to 2020 are on average higher by as much as $0.78/G or about a 4% increase. The higher increase for this scenario reflects the higher target and the significantly higher certificate price.

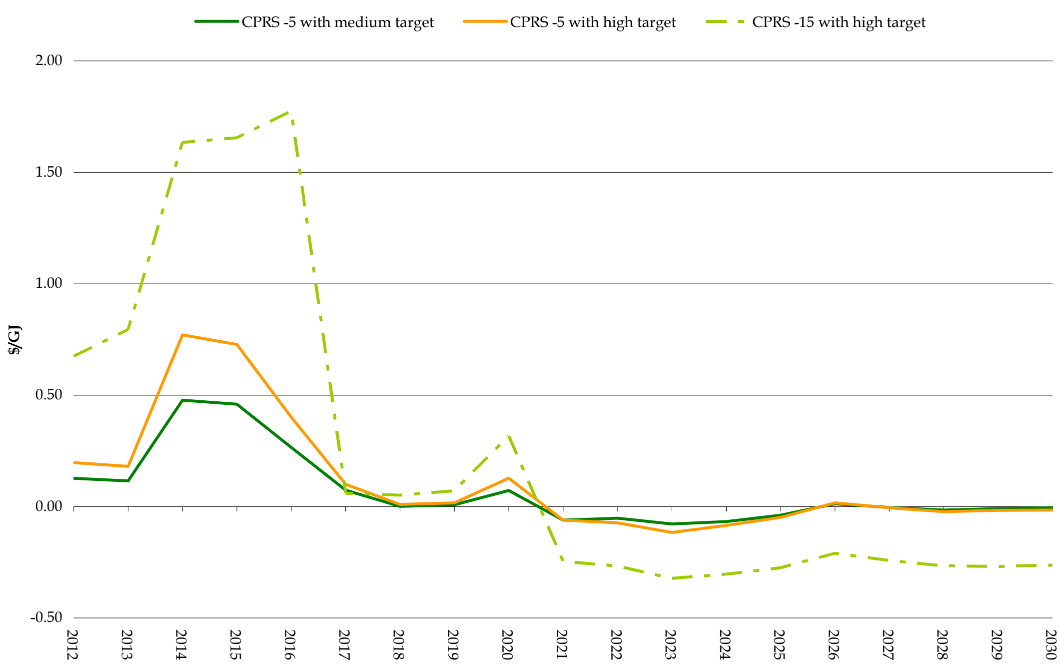
In the period after 2020, retail gas prices are lower reflecting the impact of lower demand on wholesale prices. The reduction in retail prices from 2021 to 2030 is around 1.4% for the CPRS -15 with a higher targets and around 0.2% for the energy efficiency targets under the CPRS -5 scenario.

Figure 6-11: Changes in wholesale gas prices



Source: MMA analysis.

Figure 6-12: Changes in retail gas prices



Source: MMA analysis.

6.3 Generator Profits

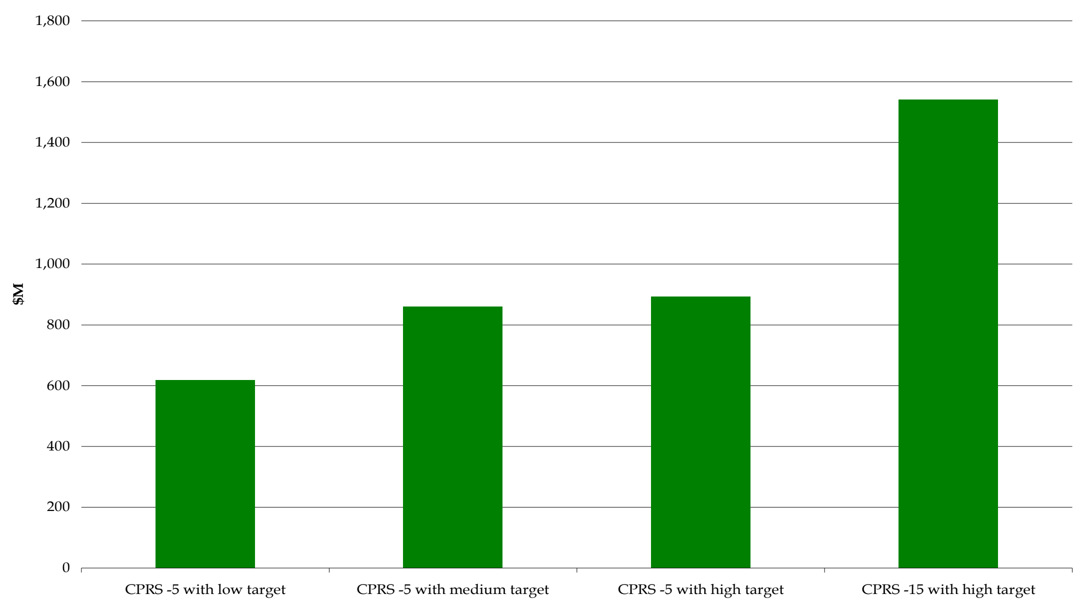
Generator profits are affected by the change in wholesale prices and for some generators the reduction in volume of generation. Because wholesale prices are likely to fall with the energy efficiency obligations target, there are downward pressure on profits as a result of the measure. For some existing generators, the level of generation also falls due to lower demand. For other existing generators the level of generation increases in some years as the lower energy demand delays the entry of new plant with lower short run marginal costs.

Overall, profits for existing generators are predicted to fall slightly. On a present value basis, the fall in profits in the period from 2012 to 2020 ranges from $600 million for a low target to $900 million for a high target under a CPRS -5 carbon price regime, and around $1,500 million under the high energy efficiency target with a CPRS -15 carbon price regime[6].

The estimates of profit reduction should be treated with caution as the estimates are based on changes in trading profits and do not take into account any protection afforded under existing contract arrangements.

Nonetheless, the reduction in profits under the energy efficiency obligation scheme could advance the retirement of some high emission plant under the CPRS.

Figure 6-13: Reduction in generator profits due to the energy efficiency obligations scheme



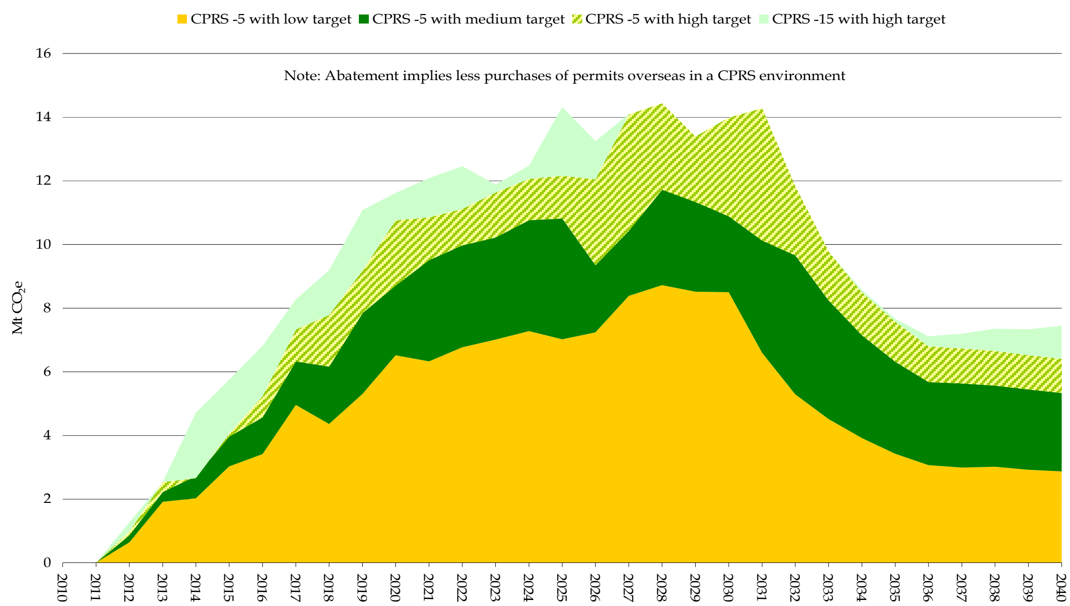
Source: MMA analysis.

6 The present value of the change in profit to 2020 was calculated using a commercial weighted average cost of capital of 10.6 percent.

6.4 Emissions Savings

The energy efficiency obligation scheme leads to a reduction in emissions from electricity generation due to a reduction in coal and gas-fired generation. Under the CPRS -5, emissions in 2020 are reduced by 7 Mt CO_2e for the low target and up to 11 Mt CO_2e for the high target, and emissions in 2030 are reduced by 11 Mt CO_2e to 14 Mt CO_2e respectively. Over the period from 2012 to 2030 emissions are reduced by 108 Mt CO_2e with a low target and 176 Mt CO_2e with a high target. Under the high target proposed for the CPRS -15 scenario, emissions in 2020 are reduced by 12 Mt CO_2e and in 2030 by 9 Mt CO_2e. Emissions to 2030 are reduced by 180 Mt CO_2e. Under an emission trading scheme with a carbon permit price set internationally, the reduced level of emissions is largely reflected in reduced purchases of permits from overseas.

Figure 6-14: Abatement of CO_2e emissions from electricity generation



Source: MMA analysis.

7 CONCLUSIONS

7.1 Key Findings

Energy supply is both a key driver for economic growth and a major source of greenhouse gas emissions in Australia.

Achievement of the objectives of the energy efficiency obligation requires an understanding that, as a highly capital intensive industry, the energy sector as a whole, and electricity in particular, works on a large scale with very long lead times and long payback times for investors.

Energy efficiency will be critical to how the energy sector meets a number of key challenges before it. They include:

- Investing large amounts of capital in generation and network assets to meet growing demand for energy. Energy efficiency programs will delay the need to invest in this new capacity.
- Protecting against volatile and rising prices as the demand-supply balance tightens and as an emission trading scheme is implemented.
- Reducing greenhouse gas emissions and other pollutants from the supply of electricity and gas. In recent years, the electricity supply industry has been subjected to a range of greenhouse gas abatement measures. Emissions from electricity generation below current levels will largely occur through the adoption of carbon geosequestration technologies, more widespread adoption of renewable energy and energy efficiency technologies. Fuel switching in generation and more efficient fossil fuel generation will contribute to the mitigation of growth in emissions, but will not be enough to reduce emissions over the long-term. This study indicates the high potential benefit from emission abatement from energy efficiency programs.

There are many other potential benefits of energy efficiency: retailers gain through lower exposure to high spot prices, networks through improved asset utilisation and deferral of network capital expenditures, end users through lower energy bills and better energy services and the community through better utilisation of resources and fewer adverse environmental impacts.

The question remains of how high levels of end use efficiency can be achieved in an environment where Australia offers some of the lowest electricity prices for customers in the developed world. This study indicates the potential benefits are high from realising the energy efficiency target under the energy efficiency obligation scheme.

7.2 Limitations and Uncertainties

An energy efficiency obligation scheme can bring many benefits. The scheme provides the potential for overcoming market barriers by providing financial incentives for the adoption of energy efficient approaches. When additionality rules are rigorous, the scheme could allow participants to go beyond minimum standards for appliances that would not occur under a regulatory approach. A well functioning certificate market should lead to the adoption of the least cost options for energy efficiency and can complement an emission trading in achieving emission abatement more effectively. The modelling results demonstrate the net benefits that can arise.

Nonetheless, there are some potential limitations from an energy efficiency trading scheme that have not been considered in the modelling process so the results need to be interpreted with care. The limitations include:

- Depending on how the scheme is structured the administrative and compliance costs may be higher. We have assumed an additional charge of $1/certificate to cover administration but the compliance cost to individual retailers may be higher than this.
- The scheme may crowd out other low cost greenhouse gas abatement options under the emission trading scheme. This is not an issue as long as the energy efficiency obligation scheme overcomes genuine market failures.
- Potential for market power and inefficient market structures to occur. This is less of a risk for a national scheme than for the state based schemes currently in operation.

APPENDIX A ELECTRICITY MARKET MODELLING ASSUMPTIONS - NEM

A.1 Future NEM developments

A.1.1 Committed and planned entry

The recently developing power projects and reserve plant are shown in Table A-1. Only projects which have nominated commencement dates are included. The table shows the currently mothballed or reserve capacity in the NEM and the new projects which have been committed for completion within the next four years, as is reported in the 2009 ESOO. It also shows other projects for which, according to the 2009 ESOO, planning is well advanced. Table A-1 demonstrates that new entry is alive and strong in the NEM with plenty of new projects in the pipeline to meet projected demand.

Table A-1 Mothballed and reserve capacity and recently developed new plants in the NEM

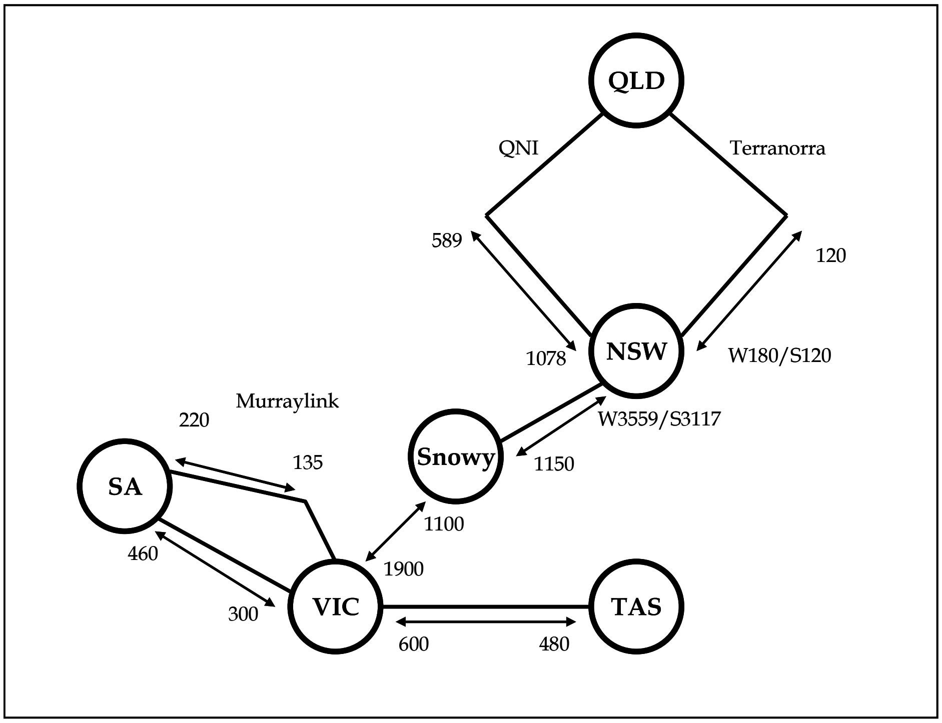
Power Plant	Generated Capacity (MW)	Region	Service Date	Status
Callide A	120 (90 long-term)	Central Qld	Originally intended to be refurbished	Mothballed in April 2002. Now in indefinite dry storage. One unit of this plant will be used to test CO_2 sequestration technology as part of low emission technology development. Modelled from 2010/11 to 2015/16.
Munmorah	2 X 300	NSW	Reserve	Both 300 MW units are operable at short notice when other Delta Electricity units are unavailable. They are not normally operated when Mt Piper and Wallerawang are fully available.
TOTAL Reserve	**690**			

Power Plant	Generated Capacity (MW)	Region	Service Date	Status
Eraring upgrade	4 x 60	NSW	Dec 11 – Nov 12	Advanced proposal
Wellington GT 1-4	4 x 173	NSW	Nov 2011	Publicly announced
Wellington GT 5	300	NSW	Dec 2012	
Leaf's Gully	360	NSW	Jan 2012	Publicly announced
Bamarang OCGT	330	NSW	Nov 2012	Publicly announced
Bamarang CCGT	450	NSW	Nov 2012	Publicly announced
Marulan OCGT	330	NSW	Nov 2013	Publicly announced
Marulan CCGT	420	NSW	Nov 2013	Publicly announced
Mt Piper Coal	1000	NSW	Nov 2015	Publicly announced
Mt Piper Coal	1000	NSW	Nov 2016	Publicly announced
Braemar stage 3	3 x 173	QLD	March 2012	Publicly announced
Braemar stage 4	2 x 236.5	QLD	Dec 2013	Publicly announced
Mt Stuart GT 3	126	QLD	Dec 2009	Committed
Yarwun cogen	169	QLD	May 2010	Committed
Pt Lincoln GT 3	25	SA	Jan 2010	Committed
Arckaringa IGCC	560	SA	Nov 2014	Publicly announced
Lonsdale 2	28	SA	Jan 2010	Publicly announced
Kingston	40	SA	2015	Publicly announced
Loy Yang	90	VIC	November 2012	Committed
Mortlake GT	2 x 275	VIC	October 2010	Committed
Tarrone GT	500	VIC	Jan 2012	Publicly announced
Shaw River CCGT	500	VIC	June 2012	Publicly announced
HRL IDGCC	500	VIC	2013	Publicly announced
Gunns	176	TAS	2012	Advanced proposal
Total Planned	**9,378**			
TOTAL	10,068			Includes reserve, new and prospective developments with advanced proposal status or likely to proceed.

A.1.2 Interconnections

Assumptions on interconnect limits are illustrated in Figure A-1. These limits are based on the maximum recorded inter-regional capabilities for 2005/06. The actual limit in a given period can be much less than these maximum limits, depending on the load in the relevant region and the operating state of generators at the time.

Figure A-1 Representation of interconnectors and their limits



Basslink has a continuous capacity of 480 MW and a short-term rating up to 600 MW. Prior to CPRS Basslink has been modelled with an optimised export limit that best uses the available thermal capacity of the cable to maximise the value of export trade. The optimisation was performed using a Strategist simulation to assess Victorian price versus export. The import limit was represented as a function of Tasmanian load according to the equation published by AEMO. This allows 323 MW of import at 800 MW and 427 MW at 1,100 MW of load.

After the CPRS the increase in off-peak prices tends to negate any consistent use of short-term rating in peak periods due to the value of the loss of transfer capability in off-peak periods necessary for cooling the cable thereafter. We therefore model Basslink after CPRS as having 480 MW continuous capacity in each direction.

There are a number of possible interconnection developments being considered including[7]:

- An upgrade of the QNI export limit by an additional 400 MW in both directions
- An upgrade of the existing Victoria to South Australia export limit from 460 MW to 630 MW
- A further 600 MW upgrade of the Snowy to Victoria transmission link over time which would enable additional imports from Snowy/NSW into Victoria.

7 Based on recent announcements by AEMO as well as statements made in the SOO 2009.

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

A.1.3 Transmission

Inter-regional losses

Inter-regional loss equations are modelled in Strategist by directly entering the Loss Factor equations published by AEMO except that Strategist does not allow for loss factors to vary with loads. Therefore we allow a typical area load level to set an appropriate average value for the adjusted constant term in the loss equation. The losses currently applied are those published in the AEMO 31 March 2009 Report V2.0 "List of Regional Boundaries and Marginal Loss Factors for the 2009/10 Financial Year".

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

Intra-regional losses

Intra-regional losses are applied as detailed in the AEMO 31 March 2009 Report V2.0 "List of Regional Boundaries and Marginal Loss Factors for the 2009/10 Financial Year". The long-term trend of marginal loss factors is extrapolated for two more years and then held at that extrapolated value thereafter.

A.1.4 Hydro modelling

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

These monthly energy limits provided by NEMMCO in the 2003 ANTS[8] have been validated by comparison against historical hydro sequences that are derived from published generation data found at www.erisk.net. Erisk is a live source of combined news, prices, data and analyses for the Australian Energy Market. Where the hydro sequences appear ill-aligned to the NEMMCO energy limits, the average monthly generation levels are used in place of the NEMMCO limits to represent an estimate of the long run monthly energy limits.

Tables A-2 through to A-4 shows the maximum monthly energy limits used in our model.

Based on our market information we have produced detailed information on monthly and annual maximum and minimum energy limits for the Snowy Hydro units. This

[8] NEMMCO no longer models hydro units using monthly energy limits in their SOO studies.

information has been incorporated into the Strategist simulation as monthly energy generation. Daily release constraints cannot be modelled in Strategist.

Table A-2 Maximum monthly energy availability for small hydro generators (GWh)

Month	Barron Gorge	Hume NSW	Hume VIC	Kareeya
January	13.96	4.19	18.75	23.32
February	20.56	3.44	15.19	22.91
March	22.63	0.22	14.53	23.60
April	15.47	0.21	6.53	20.42
May	11.28	0.00	0.62	25.02
June	9.40	0.00	0.09	25.80
July	10.07	0.94	0.01	32.05
August	7.93	4.47	1.09	30.18
September	8.51	7.86	6.97	22.61
October	12.02	6.71	14.61	23.34
November	13.38	3.47	20.25	21.30
December	10.52	5.91	20.66	28.05

Table A-3 Maximum monthly energy availability for Southern Hydro units

Month	Dartmouth	Eildon 1-2	Kiewa/ McKay
January	24.98	19.13	10.01
February	26.37	14.71	10.6
March	11.87	15.51	5.98
April	3.48	7.49	4.33
May	4.71	1.37	11.44
June	9.58	0.32	19.4
July	36.78	0.88	28.89
August	34.77	3.3	23.06
September	31.76	4.98	30.8
October	33.33	7.4	43.71
November	35.99	8.98	23.03
December	31.14	17.6	15.93

The monthly minimum generation limits for Blowering and Guthega are based on market information acquired by MMA, largely driven by the irrigation requirements of these hydro systems. While the generation from individual hydro units may differ from what has been historically observed over the past couple of years, the long-run average total Snowy generation assumed on a calendar year basis is approximately 500 GWh higher than the average of the actual Snowy generation for calendar years 2004 and 2005.

Murray 1 releases will be progressively reduced with increasing environmental releases, particularly down the Snowy River. Snowy Hydro estimates a reduction of 540 GWh/year after the 10 year programme is completed. Consequently, by July 2012 the Murray annual energy limit has been reduced to 1,738 GWh per annum.

Table A-4 Maximum and minimum energy limits from Snowy Hydro

	Blowering	Guthega	Murray	Upper Tumut	Lower Tumut
Annual Maximum Limit (GWh)	**240**	**250**	**2210**	**1630**	**745**
Monthly Minimum Limits (GWh)	(Blowering & Guthega)				
January	60		9	1	5
February	50		4	1	5
March	45		4	1	5
April	25		4	1	5
May	10		9	1	5
June	15		23	2	10
July	20		24	2	14
August	20		23	2	15
September	30		42	3	15
October	60		125	10	15
November	80		79	6	10
December	70		23	2	5
Daily Maximum (GWh)			13	12	3.6

Snowy Hydro has announced it cannot currently meet its minimum environmental flow requirements due to drought conditions[9]. To replicate the drought conditions, minimum flows have been assumed for 2007 growing linearly toward the projected environmentally reduced flows in 2011.

Hydro Tasmania is represented by the aggregate of a 3-storage model:

- Long-term storage, which is assumed to have sufficient storage for at least one year
- Mid-term storage, which is assumed to be managed on a 6-monthly basis
- Run-of-the-River, with storage possible for only one month at a time

Allocation of individual generators to each of these storages has been based on the 2006 ANTS allocation, as shown in Table A-5. However, in Strategist the monthly energy and capacity are combined into one equivalent hydro unit for Hydro Tasmania.

9 6th November 2006, 'The Australian' newspaper article 'Snowy Hydro gives flow warning'.

Table A-5 Allocation of units to storage in Tasmania

Storage	Stations
Long-term	Gordon, Poatina
Mid-term	Butlers Gorge, Lake Echo,Tarraleah, Tungatinah, Liapootah, Wayatinah, Catagunya, Repulse, Cluny, Fisher, Rowallan, Lemonthyme, Mackintosh, Bastyan, John Butter, Lake Margaret
Run of river	Meadowbank, Trevallyn, Wilmot, Cethana, Devils Gate, Paloona, Reece, Tribute, Parangan, Todds Corner

In the 2006 ANTS, energy inflow data was determined for each storage based on historical monthly yield information provided by Transend. These monthly energy inflows are represented in Table A-6.

The average annual yield is assumed to increase after the commissioning of Basslink, and so the monthly limits are pro-rated each year in line with this annual yield which appears in Table A-7. The generation profile may be distributed over the months of the year to optimise the value of trading according to the requirements of the study.

Table A-6 Monthly energy inflows for Tasmanian hydro

Average monthly yield 1924 to 2002 (GWh)													
Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Long-term	77	66	86	197	288	330	399	417	366	292	192	141	2851
Mid-term	147	120	145	325	462	495	601	595	530	435	313	230	4398
Run of river	131	110	125	206	275	311	364	364	320	280	221	177	2884
Total	355	296	356	728	1025	1136	1364	1376	1216	1007	726	548	10133

Source: ANTS 2006

Table A-7 Assumed average annual generation from Tasmanian Hydro generators (GWh)

Financial Year	2010	2011	2012	2013	Thereafter
Average annual generation	8249	8831	9309	9500	9500

Source: MMA estimate.

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.

- Snowy Hydro annual generation has been reduced only for the Tumut scheme in the 2009 financial year to 95% of the long-term average. Full recovery is assumed thereafter.

- 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 from the previously assessed allowance of 10,500 GWh to 8,249 GWh in 2009/10, rising to 9,000 GWh from 2012/13 and thereafter. The annual generation level increases linearly to 9,000 GWh in 2012/13 to reflect gradual recovery from the drought.

APPENDIX B COSTS AND PERFORMANCE OF THERMAL PLANTS - NEM

The following table shows the parameters for power plants used in the Strategist model.

Plant	No Units	Total Sent Out Capacity	Scheduled Maintenance (Weeks pa)	Effective Forced Outage Rate	Available Capacity factor	Full Load Heat Rate (Sent out)	Variable O&M Cost $/MWh (Sent out)
Tasmania							
Tamar Valley CCGT	1	196.9	1.9	3%	93.6%	7.54	$2.69
Bell Bay GT	3	119.4	3.0	1%	93.3%	11.50	$4.03
Tamar Valley OCGT	1	57.7	3.0	1%	93.3%	11.50	$4.03
New Tas CCGT	*prospective*	196.0	2.5	3%	92.3%	8.00	$3.37
New Tas GT	*prospective*	160.0	2.5	2%	93.3%	11.00	$5.73
Victoria							
AGL	4	159.2	4.0	9%	84.0%	13.50	$2.69
Anglesea	1	146.3	1.0	2%	96.6%	13.00	$1.34
Bairnsdale	2	91.5	3.0	1%	93.3%	11.50	$4.03
Energy Brix	5	150.9	5.0	4%	86.8%	21.25	$2.69
Hazelwood	8	1472.0	4.0	9%	84.0%	13.30	$2.69
Jeeralang A	4	230.8	2.1	1%	95.0%	13.75	$8.06
Jeeralang B	3	253.7	2.1	1%	95.0%	12.85	$8.06
Laverton	2	338.3	2.0	2%	93.9%	11.55	$4.03
Loy Yang A	4	2043.0	2.5	4%	91.9%	11.58	$1.07
Loy Yang B	2	966.0	2.5	3%	92.3%	11.70	$1.07
Valley Power	6	313.4	2.1	1%	95.0%	13.75	$8.06
Yallourn W	4	1368.0	3.0	6%	88.6%	12.91	$1.34
Newport	1	484.5	2.2	3%	93.0%	10.33	$2.69
Mortlake OCGT	2	550.2	2.5	2%	93.0%	10.60	$3.42
Mortlake CCGT	*prospective*	490.0	2.5	2%	93.0%	7.21	$3.42
Shaw River CCGT	*prospective*	490.0	2.5	2%	93.0%	7.21	$3.42
Generic VIC CCGT	*prospective*	392.0	2.5	3%	92.3%	7.21	$3.27
Generic VIC GT	*prospective*	160.0	2.5	2%	93.3%	11.00	$2.29
HRL	*committed*	403.0	2.0	20%	76.9%	7.17	$3.25

Plant	No Units	Total Sent Out Capacity	Scheduled Maintenance (Weeks pa)	Effective Forced Outage Rate	Available Capacity factor	Full Load Heat Rate (Sent out)	Variable O&M Cost $/MWh (Sent out)
South Australia							
Angaston	1	48.8	0.0	0%	99.5%	9.00	$11.53
Dry Creek	3	147.3	4.0	3%	89.1%	17.00	$8.06
Hallett	4	187.1	4.0	5%	87.9%	12.00	$9.20
Ladbroke Grove	2	85.6	3.0	2%	92.1%	10.00	$6.72
Mintaro 1	1	89.6	4.0	5%	88.1%	16.00	$8.06
Northern	2	505.1	2.8	2%	92.6%	11.50	$2.61
Osborne	1	187.4	2.0	2%	93.9%	10.40	$2.61
Pelican Point	1	462.6	3.0	3%	91.4%	7.71	$2.69
Playford B	4	222.0	6.0	5%	84.1%	15.00	$3.92
Port Lincoln	3	74.6	3.0	3%	91.4%	11.67	$8.06
Quarantine	5	217.9	4.0	3%	89.1%	10.35	$8.57
Snuggery	3	65.7	4.0	5%	88.1%	15.00	$8.06
Torrens Island A	4	478.8	4.0	5%	87.7%	10.80	$8.06
Torrens Island B	4	779.0	4.0	5%	87.7%	10.50	$2.02
Pelican Point CCGT	*prospective*	294.0	2.5	3%	92.3%	7.21	$3.37
SA OCGT	*prospective*	129.4	2.5	2%	93.3%	11.00	$5.62
Hallett OCGT	*prospective*	129.4	2.5	2%	93.3%	11.00	$3.73
Arckaringa IGCC	*prospective*	218.4	3.0	7%	87.6%	9.12	$1.99
NSW							
Bayswater	4	2592.7	2.5	2%	93.3%	10.00	$2.69
Colongra OCGT	4	664.7	2.5	3%	91.9%	11.84	$9.27
Eraring	4	2594.4	2.5	4%	91.8%	10.08	$2.69
Eraring GT	1	39.8	2.5	3%	91.9%	11.84	$9.27
Hunter Valley GT	2	74.6	4.0	3%	89.1%	23.38	$9.27
Liddell	4	1974.0	2.5	3%	92.3%	10.38	$2.43
Mt Piper	2	1316.0	1.0	1%	97.1%	9.93	$2.56
Munmorah	2	564.0	43.0	10%	15.8%	10.67	$2.67
Redbank	1	141.0	2.0	2%	93.9%	11.00	$2.69
Smithfield	1	151.2	3.0	20%	75.8%	10.00	$5.11

Plant	No Units	Total Sent Out Capacity	Scheduled Maintenance (Weeks pa)	Effective Forced Outage Rate	Available Capacity factor	Full Load Heat Rate (Sent out)	Variable O&M Cost $/MWh (Sent out)
Tallawarra	1	422.0	2.5	3%	92.3%	7.17	$3.41
Uranquinty	4	660.7	2.5	2%	93.3%	10.98	$3.25
Vales Point	2	1240.8	3.8	4%	89.0%	9.87	$3.36
Wallerawang	2	940.0	4.8	8%	83.9%	11.13	$4.03
Generic NSW CCGT	*prospective*	392.0	2.5	3%	92.3%	7.21	$3.31
Generic NSW OCGT	*prospective*	199.0	2.5	2%	93.3%	10.80	$2.22
Munmorah CCGT	*prospective*	400.0	2.5	3%	92.3%	7.21	$3.34
Port Kembla	*prospective*	186.2	2.5	3%	91.9%	7.10	$3.39
Tomago CCGT	*prospective*	735.0	2.5	3%	92.3%	7.21	$3.16
Tomago OCGT	*prospective*	248.8	2.5	2%	93.3%	10.60	$2.11
Bamarang OCGT	*prospective*	328.4	2.5	2%	93.3%	10.60	$2.11
Bamarang CCGT	*prospective*	441.0	2.5	3%	92.3%	7.21	$3.16
Marulan OCGT	*prospective*	328.4	2.5	2%	93.3%	10.60	$2.25
Marulan CCGT	*prospective*	411.6	2.5	3%	92.3%	7.21	$3.37
NSW CCGT CCS	*prospective*	450.0	2.5	3%	92.3%	8.00	$4.23
NSW IGCC CCS	*prospective*	472.5	3.0	7%	87.6%	11.40	$2.91
Queensland							
Barcaldine CC	1	48.8	3.0	3%	91.4%	8.02	$4.03
Braemar	6	964.2	2.0	2%	94.2%	11.00	$3.38
Callide A	Reserve	120.0	3.0	5%	89.5%	13.70	$2.02
Callide B	2	658.0	2.0	3%	93.3%	9.88	$1.93
Callide C	2	846.0	1.2	6%	91.9%	9.00	$1.34
Collinsville	5	174.9	3.0	5%	89.5%	13.70	$2.69
Darling Downs	1	617.4	2.0	1%	95.2%	6.70	$3.34
Gladstone	6	1579.2	2.4	5%	91.1%	10.22	$1.18
Invicta	1	0.0	4.0	86%	13.1%	12.00	$1.34
Kogan Creek	1	699.4	3.0	3%	91.4%	9.50	$1.21
Mackay GT	1	31.8	2.0	2%	94.2%	13.50	$10.75
Millmerran	2	783.8	3.0	8%	86.5%	9.88	$1.21
Mt Stuart GT	3	412.9	2.0	2%	94.2%	11.50	$5.37

Plant	No Units	Total Sent Out Capacity	Scheduled Maintenance (Weeks pa)	Effective Forced Outage Rate	Available Capacity factor	Full Load Heat Rate (Sent out)	Variable O&M Cost $/MWh (Sent out)
Oakey GT	2	328.4	2.0	2%	94.2%	11.50	$5.37
QAL Cogen	1	150.0	2.5	1%	94.3%	7.00	$3.38
Roma	2	67.7	4.0	9%	84.0%	13.50	$5.37
Stanwell	4	1380.9	1.8	1%	95.6%	9.99	$1.07
Swanbank B	4	448.8	3.0	10%	84.8%	10.81	$2.69
Swanbank E	1	358.9	2.0	2%	94.2%	8.10	$2.69
Tarong	4	1316.0	2.2	2%	94.2%	10.06	$1.12
Tarong North	1	416.4	2.4	2%	93.9%	9.00	$1.12
Yabulu	1	235.7	3.0	2%	92.4%	7.44	$2.69
Qld North CCGT CCS	*prospective*	450.0	2.5	3%	92.3%	8.00	$4.75
Qld North OCGT	*prospective*	129.4	2.5	2%	93.3%	11.00	$6.18
Qld North CCGT	*prospective*	166.6	2.5	3%	92.3%	8.00	$3.80
Qld South CCGT	*prospective*	385.0	2.5	3%	92.3%	7.21	$3.56
Qld South OCGT	*prospective*	144.8	2.5	2%	93.3%	11.00	$3.47
Swanbank F	*prospective*	392.0	2.5	3%	92.3%	7.21	$3.38
Qld South CCGT CCS	*prospective*	450.0	2.5	3%	92.3%	8.00	$4.45
Spring Gully CCGT	*prospective*	485.0	2.5	3%	92.3%	7.21	$3.32
Braemar OCGT	*prospective*	172.1	2.5	2%	93.3%	11.00	$3.23
Qld Central IGCC	*prospective*	553.8	3.0	7%	87.6%	9.12	$1.93
Qld Central CCGT	*prospective*	380.0	2.5	3%	92.3%	7.60	$3.12
Qld Central IGCC CCS	*prospective*	472.5	3.0	7%	87.6%	11.40	$2.79

* 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 SCHEMES INFLUENCING THE ELECTRICITY MARKET

Summary of environmental schemes influencing the NEM

Scheme	Objectives	Scope	NEM Impact	Future Prospects
LRET/SRES	To bring 45,000 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 by about 5 years. 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. Will be affected by complementary schemes such as the Solar Flagship Program and state based solar energy targets.
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.	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 – Will be made redundant when CPRS is implemented.
NSW GGAS	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 or 2020 if CPRS does not proceed. In modelling assumes 7.10 t/capita target remains until 2020 or as long as scheme remains in operation.