SINCLAIR KNIGHT MERZ

SKM

MODELLING THE RENEWABLE ENERGY TARGET REPORT FOR THE CLIMATE CHANGE AUTHORITY

DECEMBER 2012

Contents

Executive Summary

Support for development of renewable energy in Australia has accelerated over the past decade. The Mandatory Renewable Energy Target commenced in April 2001, with the objective of achieving a 2 percentage point increase on the 1997 benchmark in the level of renewable energy generation by 2010. This evolved into the expanded Renewable Energy Target (RET) Scheme in 2009, with a new target of 45,000 GWh by 2020. This scheme has since been divided up into the Small-scale Renewable Energy Scheme (SRES), covering generation from small scale sources, and the Large-scale Renewable Energy Target Scheme (LRET).

The Renewable Energy (Electricity) Act 2000 drives the RET, and under this legislation there is a requirement for biennial reviews of the legislation. As part of this review process, SKM MMA have been engaged by the Climate Change Authority to model the impact of the existing RET, and potential variations to the RET, on Australia-wide electricity markets. Key criteria to be investigated are the impacts on wholesale and retail prices, household bills, renewable development, system reliability, resource cost and emissions. SKM MMA has also investigated the impact of changing carbon price assumptions and changing demand assumptions on the effectiveness of the RET.

In performing this work, SKM MMA have utilised four models to analyse the various aspects of the markets considered. These include:

- STRATEGIST – models the Australia wide electricity markets probabilistically, on an hourly time interval looking at typical weeks each month;
- REMMA – models the large scale renewable energy development to meet the RET;
- DOGMMA – models the small scale renewable energy market sector; and
- PLEXOS - models the National Electricity Market (NEM) in detail on an hourly time interval using Monte Carlo simulations, and includes system normal transmission constraints.

Seven core cases have been defined and investigated. These include:

- Reference Case 1 – models the Australian Energy Market Operator's (AEMO) current medium demand forecast for the NEM and equivalent forecasts for other electricity markets with the existing RET target (41,000 GWh) and a carbon price that is assumed to fall from July 2015 and then return to the Treasury Core Policy carbon price in 2023;
- No RET – based on Reference Case 1 but with no RET target from 1st January 2013;
- Updated 20% Target – based on Reference Case 1 but with an updated 20% target (26,400 GWh) based on the current AEMO and equivalent medium demand forecasts;
- Combined LRET & SRES - based on Reference Case 1 but with SRES and LRET recombined into one target of 45,000 GWh from January 2015;
- Reference Case 2 - same as Reference Case 1 but with higher carbon price for the period 2015-2023 aligned to the Treasury core policy carbon price;
- Zero Carbon Price - based on Reference Case 1 with no carbon price from 1st July 2015; and
- Low demand - based on Reference Case 1 but with the low demand AEMO and equivalent forecasts.

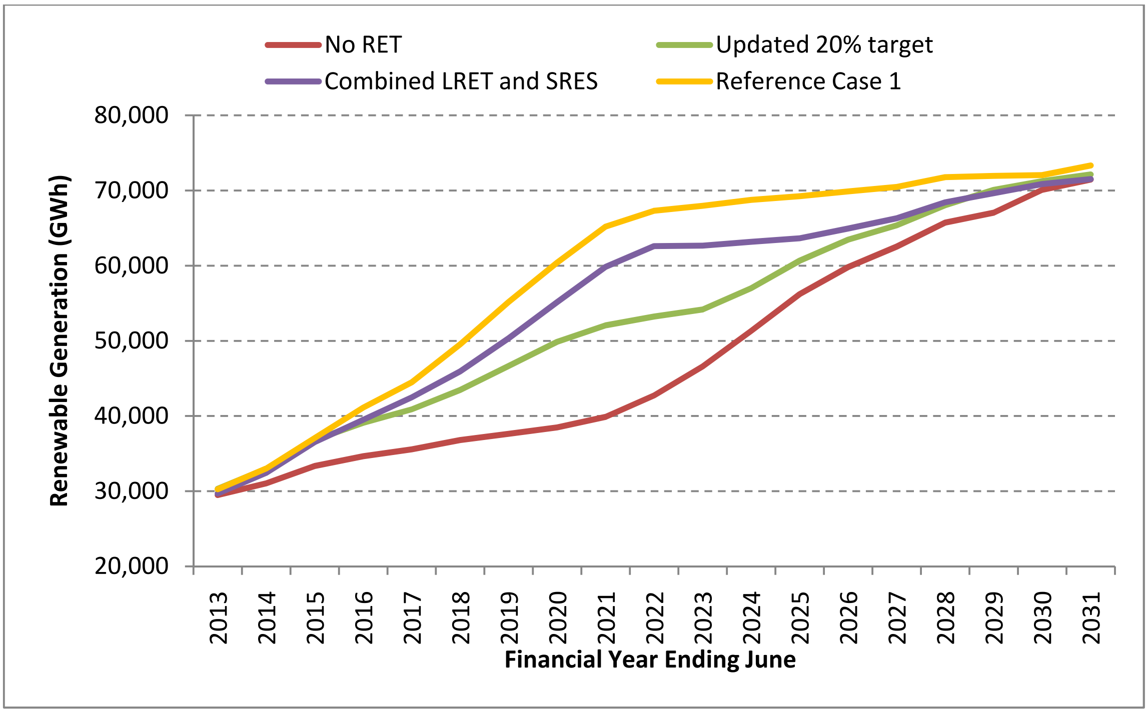
The modelling demonstrates the impact of changes to RET Scheme target, carbon price, and demand assumptions on the key criteria considered in this study. The outcomes with respect to the key criteria are summarised in the following sections.

Renewable Generation Development

As expected, a higher RET provided greater incentive and forecast more renewable development by 2020. However by 2030, renewable energy deployment is estimated to be similar in all cases as the rising carbon prices and gas prices start to drive the next round of renewable development.

A lower RET is also expected to delay renewable development that would have been deployed earlier under the existing target. For example, approximately 14,000 GWh less renewable generation development is estimated under the "Updated 20% target", but most of this development still occurs post 2023 when the modelling assumes that carbon and gas prices rise to levels that make renewable generation an economically viable alternative to new thermal generation. This is illustrated in Figure 1 which compares the renewable generation development under the various RET cases examined.

- **Figure 1 Change in renewable generation development under the various RET cases**



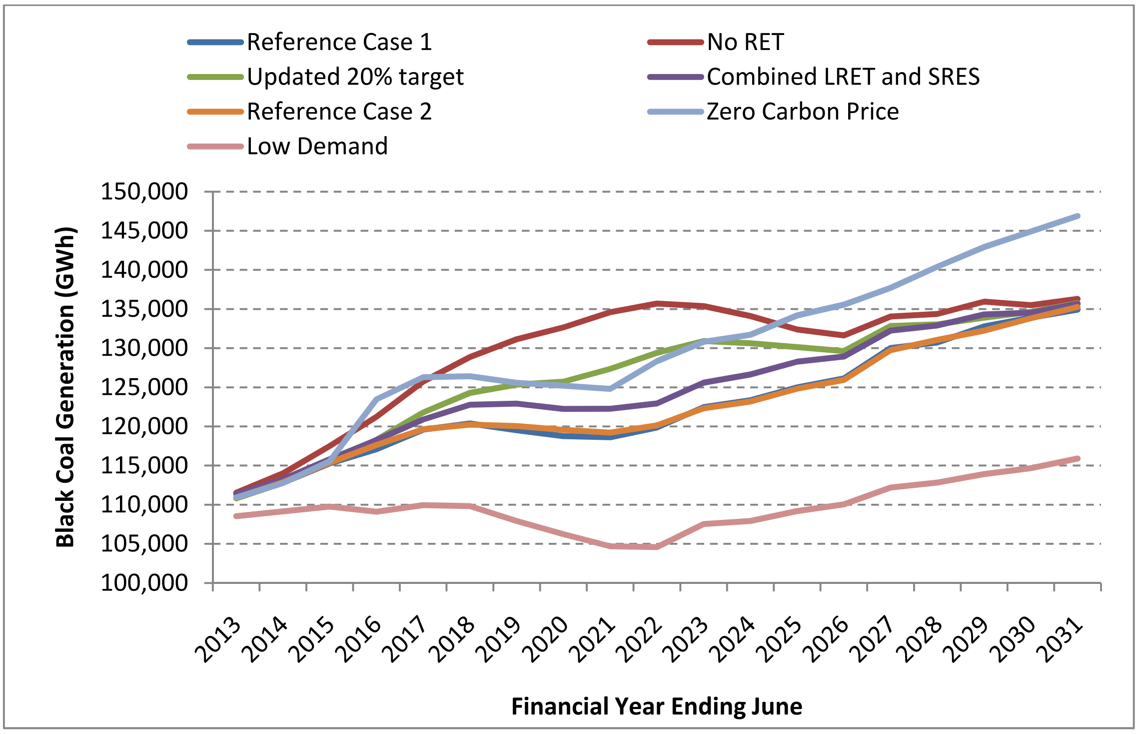
With "Zero Carbon Price" there is little or no renewable generation development post 2020 due to a substantial decrease in wholesale prices (i.e. nearly $50/MWh lower by 2030) making such projects economically unviable. The "Low Demand" case results in a slower growth of renewable generation post 2020 again due to lower wholesale prices and the lower demand growth.

Coal-fired Generation

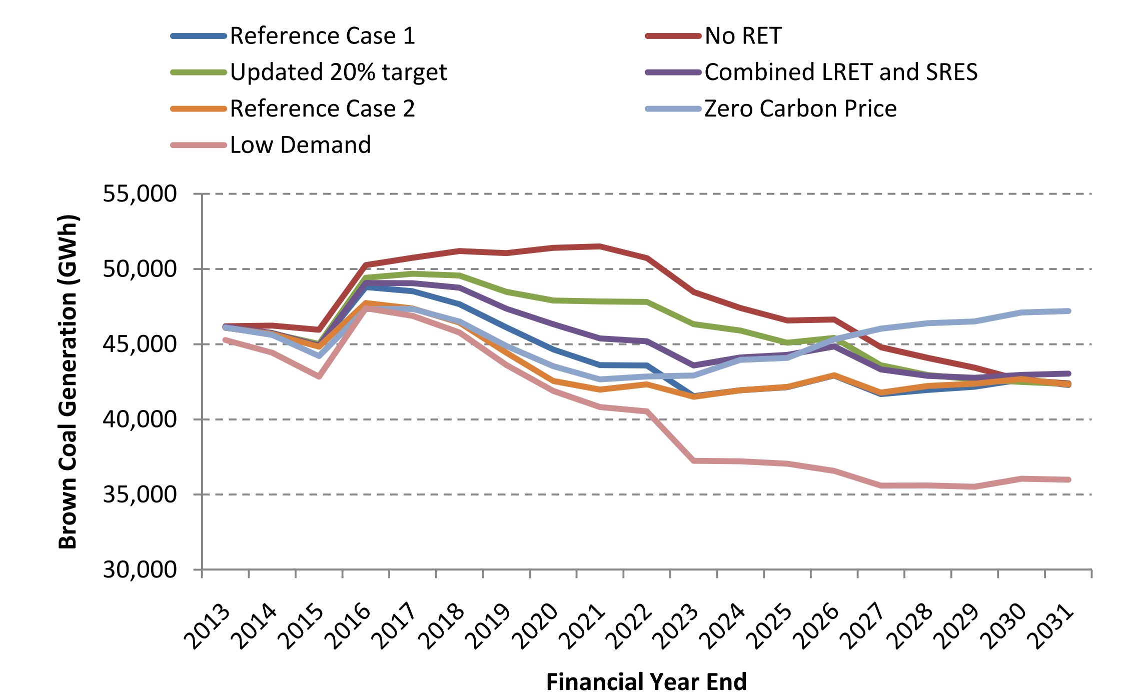
Additional renewable generation added to the current market is likely to displace existing coal-fired generation. The analysis indicates that, in GWh terms, the black coal-fired generators were impacted most by additional renewable generation, although on a percentage basis the reduction in brown coal-fired generation was slightly greater. Compared to the "No RET" case, "Reference Case 1" resulted in a reduction of approximately 15,800 GWh of black coal generation and 7,100 GWh of brown coal generation by 2022. When compared against the “Updated 20% Target”, the difference in forecast black coal generation between the two cases peaked in 2022 at around 9,500 GWh (an 8% reduction in total black coal-fired generation under “Reference Case 1”) and for brown coal displacement the difference peaked at approximately 4,200 GWh (a 9% reduction in brown coal fired generation under Reference Case 1).

The changes in black and brown coal generation between cases and from current levels are illustrated in Figure 2 and Figure 3 for black coal and brown coal generation respectively. Figure 2 shows that, while the various RET cases lead to reductions in black coal-fired generation, black coal-fired generation is still expected to increase from current levels in response to demand growth in all but the “Low Demand” case. Conversely, after an initial generation increase at the end of the three-year fixed carbon price period, brown coal generation levels generally decline over the longer term as carbon prices increase; the exception being in the ‘Zero Carbon Price” case where brown coal generation continues to be competitive with other thermal generation alternatives.

- **Figure 2 Black Coal Generation by case (GWh)**



- **Figure 3 Brown Coal Generation by case (GWh)**



Greenhouse Gas Emissions

The development of more renewable generation lowers greenhouse gas (GHG) emissions over the period. The more renewable generation developed the greater the reduction. However by 2030/31 financial year, the differences in annual GHG emission production are very similar for all the RET cases.

With a small reduction in the RET, as modelled with the "Combined LRET & SRES" target, the GHG emissions increased by around 68 Mt over the period to 2030/31. With the "Updated 20% target", emissions increased by approximately 119 Mt when compared to "Reference Case 1".

The higher carbon price included in "Reference Case 2" reduces emissions by around 12 Mt when compared to "Reference Case 1". This reduction in GHG emissions is driven by a change in generation mix, with the high carbon price leading to less coal generation and more gas-fired generation.

Resource costs

With more renewable development and fewer GHG emissions, resource costs (capital, operating and maintenance costs) increased. The difference in resource costs was most noticeable in "No RET", with a NPV[1] of approximately $8.6 billion saving compared to "Reference Case 1". For the "Updated 20% Target", the NPV of resource costs were around $4.5 billion lower than in "Reference Case 1". For a small reduction in the RET target, as modelled with the "Combined LRET & SRES", the NPV of resource costs reduced by approximately $2.4 billion compared to "Reference Case 1". In all cases, the reduction in resource cost was predominantly driven by the reduced renewable generation development. With relatively low demand growth projected in the period to 2030/31, the renewable generation development

1 The NPV was calculated based on a 7% discount rate over the period 2013-2031 financial year ending June.

was typically surplus to existing capacity rather than displacing the need for new thermal generation development.

In “Reference Case 2”, the resource costs were approximately $437 million (NPV) higher than “Reference Case 1” due to gas-fired generation displacing coal-fired generation in response to higher carbon prices.

Wholesale prices

In the current electricity market environment with surplus capacity and low demand growth, a higher RET and higher renewable development is expected to lead to lower wholesale prices, as prices are further suppressed by this additional supply. The wholesale price reductions offset the additional RET certificate cost associated with a higher RET in the short term. In the “No RET” case the difference in wholesale prices peaked at $18.1/MWh and then reduced once renewable development recommenced post 2023. In the “Updated 20% Target”, the modelling shows that wholesale prices could be up to $7.9/MWh higher than under ”Reference Case 1” prior to further renewable generation development post 2022.

”Reference Case 2” produced higher wholesale prices with only marginally more renewable generation over and above “Reference Case 1”. While in the “Low Demand” and “Zero Carbon Price” cases, lower wholesale prices are forecast resulting in higher LGC prices.

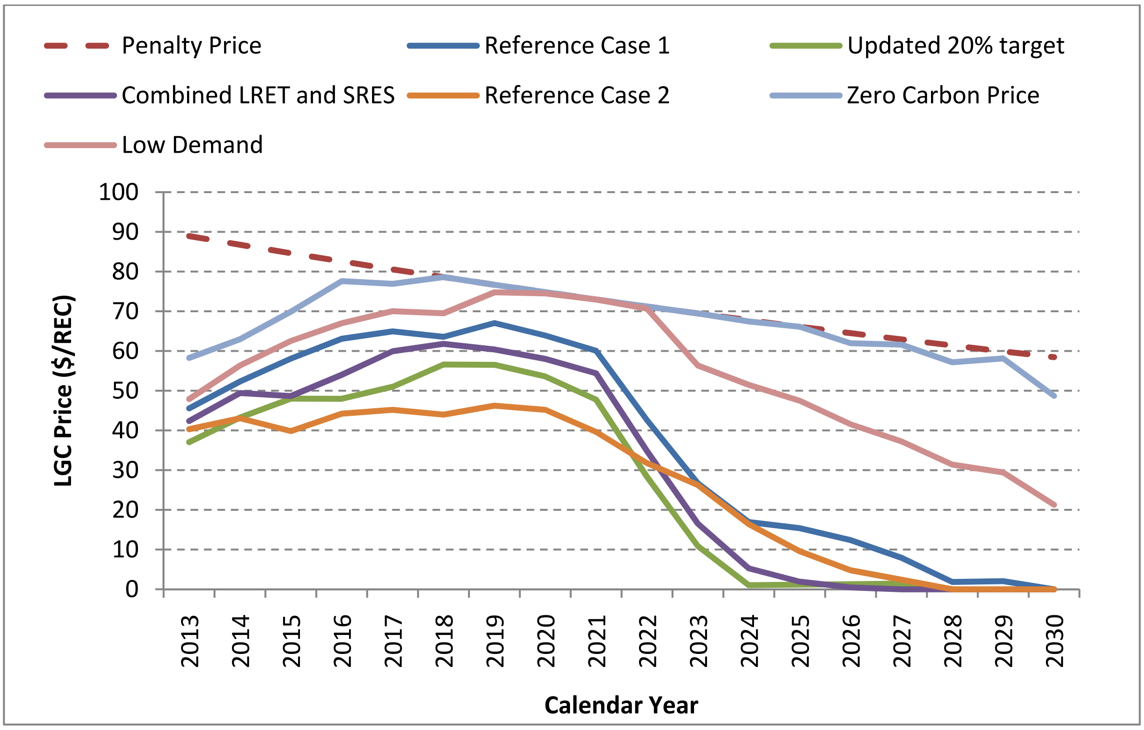
LGC prices and RET Certificate cost

As the RET increases, enabling higher-cost renewable energy resources to be developed, the LGC price increases. Comparing LGC prices across the various cases tested, the estimated LGC price is highest under “Reference Case 1”. For the “Low Demand” case and “Zero Carbon Price”, where the RET is the same as in “Reference Case 1”, the estimated LGC prices are higher still. The lower wholesale prices in these two scenarios mean that the LGC price needs to be higher in order to cover the costs of the renewable energy developments. In “Reference Case 2”, the implication of the higher carbon price modelled for the existing target is that the LGC price would drop making the existing RET easier to meet.

A comparison of the estimated LGC prices is shown in Figure 4.

In “Reference Case 1” the LGC price remains below the shortfall charge for the entire period until the end of the scheme, indicating that under the assumptions of the modelling the 41,000 GWh large-scale renewable energy target would be met. The LGC penalty price is reached in the “Zero Carbon Price” in 2018 indicating that the RET is unlikely to be met in the absence of a carbon price; the shortfall would appear to be approximately 3,500 GWh. The price needed to ensure the shortfall did not occur would be approximately $78/LGC in 2020 or approximately $3 higher than the tax effective penalty price at that time. In the “Low Demand” case, the penalty is just reached in 2021 indicating that there is also a risk under the “Low Demand” case that the RET may not be met.

- **Figure 4 LGC prices for all cases, June 2012 dollars**



The RET certificate cost in a given year represents the total cost of purchasing certificates (including administration costs), divided by relevant acquisitions. The RET certificate cost is highest for the "Low Demand" and "Zero Carbon Price" cases where LGC prices are higher. The RET certificate costs for "Reference Case 1" are expected to be approximately $12.8/MWh by 2020. Under the "Updated 20% Target", the certificate cost is expected to be approximately $5.8/MWh lower than in "Reference Case 1" in 2020.

Under "Reference Case 1", the certificate cost of meeting SRES is calculated assuming a nominal average certificate price of $31/MWh over the period to 2030. In the "Combined LRET & SRES" case, the small-scale renewable generation is assumed to receive the LGC price, which is higher than the SRES price. Therefore, in the "Combined SRES & LRET" there is an initial slight increase in certificate cost compared to "Reference Case 1" due to higher certificate prices for the SRES component. If, under "Reference Case 1", the price of small-scale certificates gradually increased to the same price as an LGC, then the differences in certificate costs between the two cases would reduce.

Retail Price/Household bills

In all the RET cases modelled, the estimated impact on the average household bill (assumed to be consuming 7 MWh per annum) was less than 1%. This was generally due to the higher RET driving wholesale prices down to an extent that they partially offset the additional certificate cost. Under the "Updated 20% Target", the retail prices were on average approximately $0.1/MWh higher than 'Reference Case 1" over the 2013-2031 period. In NPV terms, this is equivalent to an increase in the average household bill of $9 over the same period.

The estimated additional cost to the average households bill of the continuation of the existing RET (under "Reference Case 1") compared with a "No RET" scenario, was $15/annum.

The "Zero Carbon Price" cases showed a greater reduction of $208/annum in household bills over the period.

RET review participant feedback

The Climate Change Authority published its Discussion Paper and the accompanying SKM modelling report and output data on its website (www.climatchangeauthority.gov.au) in October 2012. Key issues raised by participants include that the market modelling does not appropriately consider:

- *bidding behaviour and therefore overstates the dampening of wholesale prices*: With the low wholesale prices, other generators may attempt to change their bidding strategy in order to increase prices and increase their profitability. Changes to bidding strategies to support prices at levels closer to new entry will reduce the differences in wholesale prices observed between these two scenarios. However, higher wholesale electricity prices will lead to lower LGC prices assuming that the LGC price provides the subsidy, in addition to the electricity price, that is required to make the last installed (marginal) renewable energy generator to meet the LGC target economic without further subsidisation. Therefore, the net impact on households resulting from a change in assumed bidding behaviour is unlikely to be significant. At the extreme, assuming no change in wholesale price due to LRET, it is estimated that the NPV of change in household bill with and without RET could be as much as $414 for the average household bill over the period to 2030-31 (compared to the current estimate of $154 per household). Similarly, comparing "Reference Case 1" against the "Updated 20% Target" case, the lower renewable target in "Updated 20% Target" would lead to a decrease in the average annual household bill of $9, if the generator bidding strategies adopted resulted in wholesale prices being maintained at levels observed in the "No RET" case. This is equivalent to a decrease of approximately $73 per household on a NPV basis (compared to the current estimate of $9 increase per household);
- *plant retirement*: Generator retirements are considered as part of the market modelling, and are determined based on an assessment of the economic viability of the incumbent generator. Where it is deemed that a generator would not receive sufficient revenue to recover its assumed avoidable costs over a couple of years, this generator is retired and the impact of this retirement on remaining generators is reassessed;
- *hedging costs associated with intermittent (renewable) generation*: The retail margin estimated includes the cost of purchasing electricity hedge contracts and this cost is assumed to be the same across the scenarios modelled. However, the potential cost variation between scenarios has not been explicitly modelled;
- *transmission costs associated with renewable energy deployment*: The modelling accounts for the cost of network connections and augmentations for electricity generators as part of the overall project cost. Consistent with other studies, it is assumed that the South Australia – Victoria (Heywood) transmission interconnector will be upgraded to a capacity of approximately 650 MW. Other than this upgrade, which is assumed for each scenario, no other major inter-regional transmission augmentations are required; and
- *the cost of abatement*: this report adopts the cost of emission abatement methodology outlined in the Department of Climate Change and Energy Efficiency's (2011), *Estimating the Cost of Abatement*.

Appendix B summarises the key changes to output data since the release of the Discussion Paper.

Summary

Table 1 illustrates the comparison of key variables compared to “Reference Case 1” over the period 2012/13 to 2030/31 financial year ending June.

- **Table 1 Change in key parameters compared to “Reference Case 1”**

Case	NPV change in Resource cost ($M)	Change in Emissions (Mt)	Average change in RET certificate cost to 2031 ($/MWh)	Average Wholesale price change# ($/MWh)	Average Retail Price change# ($/MWh)	NPV of Household bill Change ($)^
Updated 20% target	-4,457	119	-3.9	3.4	0.1	9
No RET	-8,645	217	-9.7	6.7	-2.1	-154
Combined LRET and SRES	-2,390	68	-1.1	1.7	0.9	70
Reference Case 2	437	-12	-1.9	7.9	7.1	595
Zero Carbon Price	2,035	137	1.5	-27.7	-29.7	-1611
Low Demand	-5,938	-349	1.7	-13.7	-14.4	-827

^NPV over 2013-2031 period assuming a 7% discount rate and assuming average annual household consumption of 7 MWh,
average for period 2013-2031 financial year.

A change in RET has both positive and negative impacts for consumers. The existing RET drives more renewable development which in the short term is expected to lower wholesale prices and reduce the impact on the average household bill. Emissions are also abated earlier due to earlier development of renewable energy generation.

Conversely, the higher RET results in higher resource costs and even a small reduction in the RET, as modelled in the “Combined LRET & SRES”, lowers the resource cost by $2.4 billion (NPV). In this case, the emissions increased by 68 Mt with an effective cost of the additional emissions of $35/t[2].

[2] Based on cost of abatement methodology recommended in DCCEE (2011) “Estimating the Cost of Abatement”, http://www.climatechange.gov.au/~/media/publications/abatement/20111011-estimating-the-cost-of-abatement-pdf.pdf

1. Introduction

SKM MMA has been engaged by the Climate Change Authority to undertake modelling to determine the market impacts of potential changes to the Renewable Energy Target (RET) Scheme.

The analysis examines seven future cases which investigate different target levels for the RET, various carbon prices and different levels of electricity demand. The analysis examines each case and provides comparison of the scenarios to gain an understanding of the impact on a number of key criteria. The key criteria include;

- renewable generation development levels,
- Greenhouse Gas (GHG) emission levels,
- wholesale and retail prices,
- household bills,
- RET certificate cost and
- resource cost.

This report outlines the key assumptions in the modelling, the cases investigated and summarises the key results.

Unless otherwise stated, all monetary values are reported in real June 2012 dollars. NPV has been calculated over the period 2012/13 to 2030/31 financial year ending June, using a 7% discount rate.

2. Issues

The RET is designed to increase the proportion of electricity supplied in the wholesale market from renewable energy sources to facilitate the transition away from fossil fuels in order to reduce Greenhouse Gas (GHG) emissions, particularly carbon dioxide. The Climate Change Authority is conducting a review of the Renewable Energy (Electricity) Act 2000 and released an Issues Paper and Discussion paper in August and October 2012, respectively. The key questions that are being considered in the review were presented in the Issues Paper (page 25) and are replicated in the Figure 5.

▪ **Figure 5 Questions for consideration in the RET Review**

Questions

Are the existing 41,000 GWh LRET 2020 target and the interim annual targets appropriate? What are the implications of changing the target in terms of economic efficiency, environmental effectiveness and equity?

Is the target trajectory driving sufficient investment in renewable energy capacity to meet the 2020 target? How much capacity is needed to meet the target? How much is currently committed? Has the LRET driven investment in skills that will assist Australia in the future?

In the context of other climate and renewable policies, is there a case for the target to continue to rise after 2020?

Should the target be a fixed gigawatt hour target, for the reasons outlined by the Tambling Review, with the percentage being an outcome?

Should the target be revised to reflect changes in energy forecasts? If so, how can this best be achieved – as a change in the fixed gigawatt hour target, or the creation of a moving target that automatically adjusts to annual energy forecasts? How should changes in pre-existing renewable generation be taken into account? What are the implications in terms of economic efficiency, environmental effectiveness and equity?

Source: Climate Change Authority, Renewable Energy Target Review, Issues Paper, August 2012, page 25.

In making potential changes to the target, impacts on the following key areas are of interest:

- wholesale energy prices,
- the price of renewable energy certificates (LGC),
- incumbent generator dispatch,
- plant retirements and new investment in thermal generation
- resource cost, and
- emission abatement.

3. Scenarios modelled

3.1. Key Influences in the modelling

A number of key parameters may influence the performance of the RET scheme in the future. These key parameters are:

- RET structure;
- Carbon Price;
- Energy demand forecast;
- Technology costs; and
- Fuel costs.

These parameters, and the corresponding assumptions made for this modelling exercise, are outlined below.

The planning horizon for the analysis was 2013 to 2040 (financial year ending). It was considered that modelling to 2040 should be sufficient to remove any end-effects[3] from the analysis after 2030. The results included in this report focus on the period 2013 to 2031 (financial year ending).

3.2. Renewable Energy Target

Four future RET settings were considered. These included:

- LS0 – This setting assumed no target from January 2013 onwards. It is assumed any committed projects under construction will be completed but after that no incentive through the RET will be provided and any new renewable energy development will be driven by the economic viability of the plant as influenced by energy market value.
- LS1 – This setting examined an adjustment to the energy (GWh) based on the lower medium demand forecasts that are currently being used by AEMO and the Independent Market Operator (IMO) for the South West Interconnected System (SWIS) in Western Australia. The actual energy requirement is decreased to 26,400 GWh to represent an updated 2020 target, allowing for an estimated 8,000 GWh contribution from solar PV and 3,000 GWh contribution from Solar Hot Water (SHW) as a part of SRES.
- LS2 – This is effectively a business as usual setting for the RET. This setting modelled the current target of 41,000 GWh for the large scale and estimated the likely SRES component under the current scheme, assuming an STC price similar to the current price of $31/MWh.
- LS4 – This setting looked at rolling the LRET and SRES back into one target of 45,000 GWh by the 1st January 2015.

The SRES was modelled in all cases and was modelled by the SKM MMA DOGMMA (Distributed On-site Generation Market Model Australia) model to determine the likely uptake for the forecast period, assuming

---

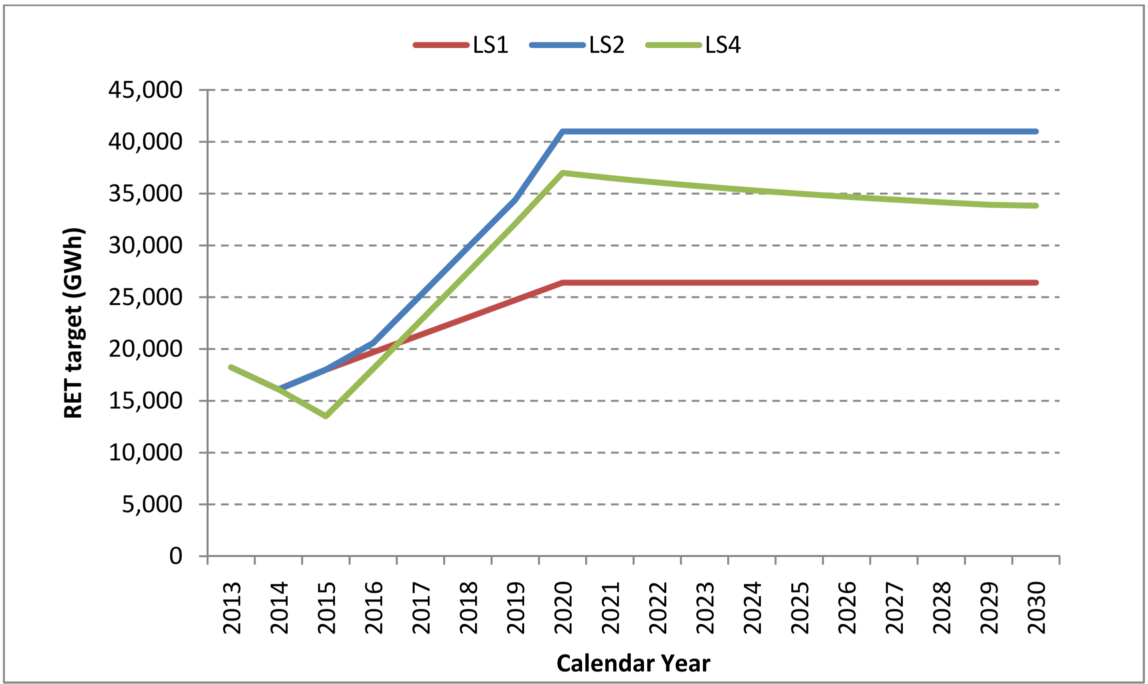
3 End effects include impacts on decisions in one case versus another case which may impact the results and conclusions but are more timing issues that would be rectified if the comparison between cases is made over a longer period.

an average nominal price of $31/certificate. A $31/certificate price was assumed as it better reflected current pricing in the market than assuming the $40/certificate maximum. Also, it is anticipated that the defining of the annual SRES target will be managed in a way to avoid prices rising and remaining at the maximum price or the price remaining low (i.e. below $20/certificate). In addition, while the average nominal price was $31/certificate, a sinusoidal shape was also modelled to provide SRES market price variability.

In the case of LS4, no distinction is made between SRES and LRET projects, and small-scale projects receive the same renewable certificate price.

Interim targets for all scenarios were appropriately scaled from January 2015 to December 2020 as shown in Figure 6.

▪ **Figure 6 Scaling of interim renewable energy targets for the scenarios**



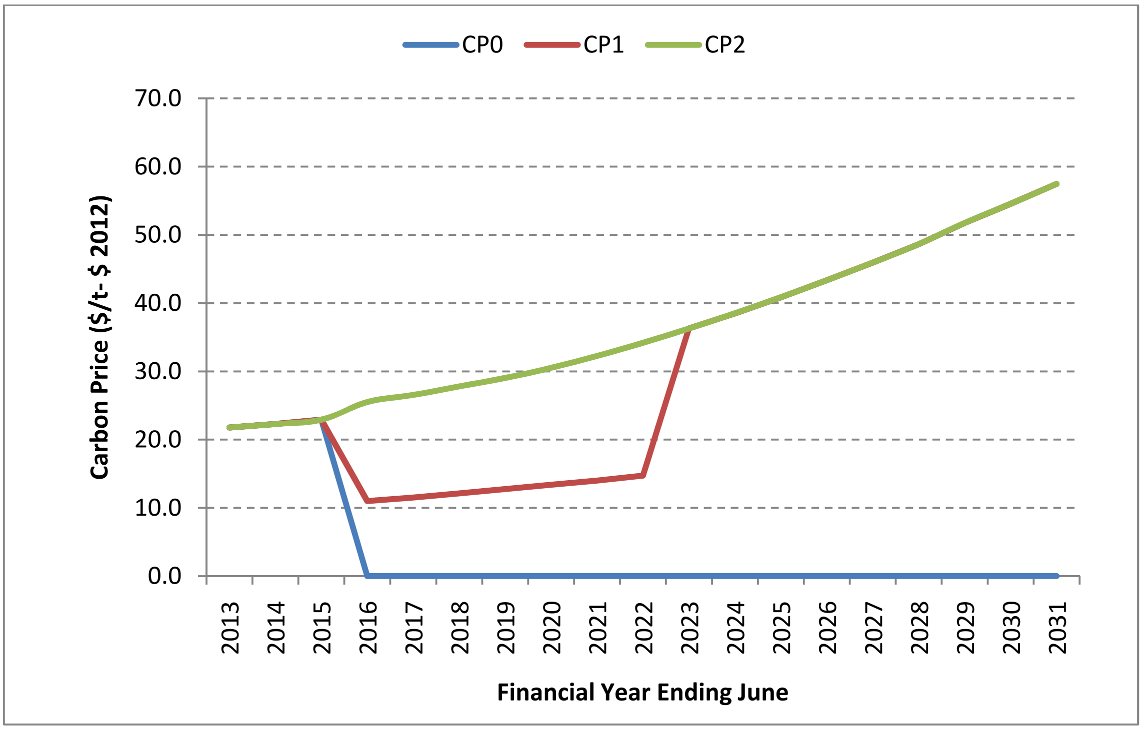
3.3. Carbon Price

Three carbon price scenarios were explored:

- CP0 – There is no price on carbon from 1 July 2015;
- CP1 – A carbon price path reflecting a fall in prices after the fixed priced period ("Reference Case 1"). This case assumes the Clean Energy Act fixed carbon prices will apply until 30 June 2015 after which the price will drop to $10.72 (June 2012 dollars); and
- CP2 – A carbon price reflective of the Commonwealth Treasury's *Clean Energy Future* (core policy scenario) modelling of $21.75/ t CO2e (June 2012 dollars) starting 1 July 2012 and rising by approximately 5.5% per annum in real terms ("Reference Case 2"). Assumed carbon prices under CP1 and CP2 converge from 2023 onwards.

These three cases are illustrated in Figure 7 below.

▪ **Figure 7 Carbon Price Scenarios, June 2012 dollars**



3.4. Energy Demand Forecast

The level of future energy demand is a major factor influencing whether RET is achieved. Therefore two different energy forecasts were considered in the modelling. For the NEM, the AEMO[4] projections were used (August 2012):

- EF1 – AEMO Low growth energy forecast
- EF2 – AEMO Medium growth energy forecast.

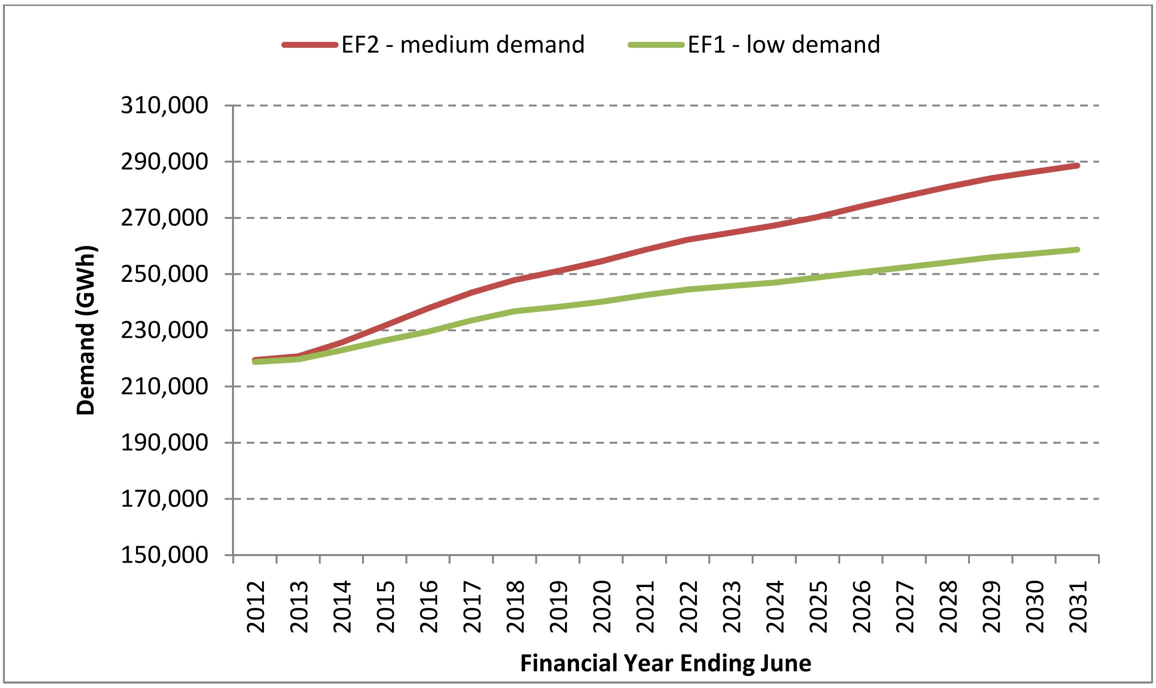
For the SWIS in Western Australia, the IMO projections reported in the 2012 Statement of Opportunities were used. For other regions, various sources have been used to define the demand forecasts (see Appendix A) including the Northern Territory Utility Commission for the Darwin and Katherine systems and Horizon Energy and other published sources on mining loads for the North West Interconnected System (NWIS) in Western Australia.

These forecasts were prepared at the wholesale level and therefore were net of assumed energy contribution from solar PV. Therefore, it was necessary to add AEMO and IMO solar PV assumptions back into the forecasts in order to assess the true native demand, and to better represent the effective wholesale load shape as it changes in the future. The native demand forecasts for each region for each case are presented in Appendix A of this report and are summarised in Figure 8. Solar PV was modelled explicitly, based on uptake determined from the DOGMMA model.

---

[4] http://www.aemo.com.au/en/Electricity/Planning/Related-Information/2012-Planning-Assumptions

▪ **Figure 8 Total Australian Native Demand for Modelling**



3.5. Other Assumptions

Other assumptions for gas and coal prices, and trends in technology costs were common to all scenarios and have been detailed in Appendix A.

3.6. Scenarios combining above parameters

If all combinations of RET, carbon price and energy forecast were considered, there would be over twenty scenarios to consider. For the purpose of this work a limited number of scenarios combining these parameters were selected. These scenarios are shown in Table 2.

▪ **Table 2 Scenarios modelled**

Case	Sensitivity parameter combination	Comments
Reference Case 1	LS2/CP1/EF2	Compared to "No RET" – to understand impact of RET on wholesale/retail pricing and investment.
No RET	LS0/CP1/EF2	This case has no RET from 2013 and is used to explore the impacts of the current RET scheme. It assumes that renewable energy projects committed in 2012 will proceed.
Updated 20% target	LS1/CP1/EF2	Looks at the impacts of a lower RET calculated as 20% of the expected native demand in 2020, less contribution from

Case	Sensitivity parameter combination	Comments
		existing renewable generation.
Combined LRET & SRES	LSC/CP1/EF2	Examines the mix of large scale and small scale renewable generation if the schemes merged in 2015.
Reference Case 2	LS2/CP2/EF2	Compares the impacts of a higher carbon price (Treasury core policy carbon price) on renewable development and the RET price.
Zero Carbon Price	LS2/CP0/EF2	Evaluates the impact of the carbon price on the RET.
Low Demand	LS2/CP1/EF1	Evaluates the impact of lower electricity demand.

3.7. RET Certificate cost calculation

The LRET certificate cost is based on the LGC price of a particular year applied to the change in renewable generation over that year. It is assumed that the mechanism for purchasing the majority of LGCs is based on project aligned power purchase agreements where the LGC at the time will fix the LRET cost for that proportion of generation for the rest of the period (i.e. to 2030). Hence by 2020 the cost of the LRET is effectively maximised assuming there would be relatively lower proportions of LGC purchased on the spot market post 2020.

Similarly, the SRES price multiplied by the volume of SRES expected in the year represents the cost for the SRES certificates.

The SRES and LRET costs are then summed and divided by the relevant acquisition value for that year. The relevant acquisition is calculated based on the expected consumption (i.e. demand net of small scale PV generation and SHW, and excluding transmission and distribution losses[5]) minus the partial exemption certificates (assumed to be equivalent to 27,000 GWh). The outcome of this is a RET certificate cost in $/MWh.

The certificate cost also includes an administration charge of $0.51/MWh.

3.8. SRES Assumptions

SKM MMA's DOGMMA determines the uptake of small-scale renewable technologies based on net cost of generation (after Feed In Tariff (FIT) revenue and other subsidies are deducted from costs) versus net cost of grid delivered power. Because the cost of renewable generation will vary by location and load factors, the model estimates uptake based on renewable resources and load levels within distribution regions. Other factors that may impact on the decision are modelled as a premium prepared to be paid for small scale renewable generation. The premium is calculated based on market survey data and other

---

5 Transmission and distribution losses are assumed to be 8% in this modelling

published market data. The premium is also assumed to decrease as the rate of uptake increases (reflecting the fact that the willingness to pay will vary among customers).

Solar PV represents the majority of small-scale renewable generation uptake determined by DOGMMA.

The number of small-scale technology certificates (STCs) created per solar PV unit depends on the solar zone in which the unit is located. The solar zone rating is an attempt to represent the amount of renewable energy generated by the system, which varies by geography based on level of sunshine. In DOGMMA, the renewable energy output from solar PV systems is explicitly modelled by region and closely aligns with these solar zone ratings. Consequently, the renewable energy output determined from the model over the lifetime of the system is used to estimate the number of STCs created. For solar PV, the lifetime of the system is assumed to be 15 years.

Additionally, Solar Credit multipliers increase the number of STCs created for small-scale solar panel, wind and hydro systems. Currently, the multiplier is set at 2, but from 1 January 2013 there will no longer be any multiplier on these systems. Therefore, this multiplier has been included in the analysis for the first six months of the 2012/13 financial year only.

There is a high degree of uncertainty surrounding future uptake of Solar Hot Water (SHW) systems. The DOGMMA modelling indicates that new SHW uptake may be much lower in the future than in the recent past due to the comparative price advantage of small scale PV systems assumed compared to SHW. It is also difficult to determine the contribution from existing and new SHW systems already included in the AEMO and IMO load forecasts. Presumably, in addition to new systems, there will be existing systems that are replaced at the end of their 10-year life and it is assumed that these replacements would also be eligible for STCs. After discussions with the Climate Change Authority it was assumed that the maximum level of SHW penetration would reach approximately 3400 GWh by 2018, including output from existing systems, but then reduce and stay at approximately 3000 GWh from 2020 onwards[6]. Given that the life of SHW is estimated to be 10 years, approximately 10% (or 300 GWh) of new/replacement installations are assumed to be installed each year post 2012. This results in three million STCs being created each year from SHW installations, based on a 10-year life.

3.9. Transmission augmentations

The national electricity market objective is essentially customer facing. There is no obligation on any transmission or distribution network service provider to construct or augment a network to allow for the dispatch of any generation unless there is insufficient capacity to meet customer demand. Network augmentation occurs on a market benefits basis where the Regulatory Investment Test for Transmission (RIT-T) considers all feasible generation, demand side and network alternatives. Within the market modelling, inter-regional transmission augmentations are considered if the benefits of augmentation are greater than the estimated cost of upgrading the network. For this analysis, it has been assumed that the VIC-SA network augmentation recommended by AEMO and Electranet in the recent Heywood RIT-T will proceed in all scenarios, increasing the capacity of that interconnector to approximately 650 MW. No other major network augmentations were required within the planning horizon considered.

Where an augmentation would only deliver increased access for a generator it is the responsibility of the generator to fund that augmentation. Our analysis considers the cost of network augmentations for generators as part of the overall project cost. There are significant renewable energy resources available

---

[6] It is assumed that the impact of this level of SHW penetration has already been included within the demand forecasts so no additional adjustment to demand has been made.

close to existing networks. Where higher quality renewable energy resources are more remote from the network it is anticipated that proponents will consider the trade-off between the higher cost of connection and the potential increase in revenue that they could receive from the better resource.

3.10. Generation retirements

Generator retirements are considered as part of the market modelling, and are determined based on an assessment of the economic viability of the incumbent generator. Where it is deemed that a generator would not receive sufficient revenue to recover its assumed avoidable costs over a couple of years, this generator is retired and the impact of this retirement on remaining generators is reassessed.

3.11. Resource cost calculation

The resource cost is calculated as the sum of:

- fuel costs of existing and new plant
- operations and maintenance (O&M) cost of existing and new plant
- the annualised capital cost of new plant.

No emission costs are included in this calculation.

In calculating the annualised cost of new plant an average discount rate of 11% is assumed to reflect the average returns required on equity and debt on new projects. The project economic life is assumed to be 20 years for calculating the annualised cost component.

4. Results

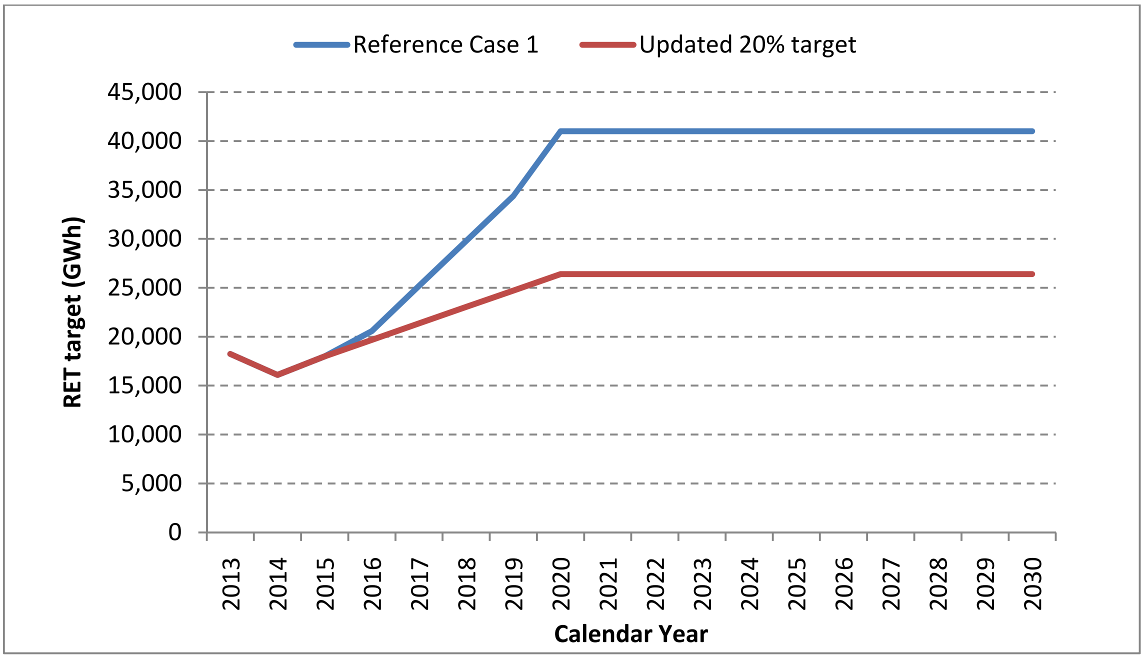
This section summarises the market impacts of the various RET scenarios analysed.

4.1. Impact of reducing the target to 20% of the 2020 demand forecast

Reducing the RET to 20% of the forecast demand in 2020 based on the current AEMO forecasts results in a target for large scale generation of 26,400 GWh as shown in Figure 9. This section compares the two following cases:

- "Reference Case 1" – Assumptions used in this scenario included existing RET (41,000 GWh), Medium Demand growth (AEMO 2012) and a lower carbon trajectory from 2015 through 2023 reflective of the potential for the carbon price to fall after the fixed price period;
- "Updated 20% target" – The updated 20% target by 2020 is based on new demand forecasts for the NEM, NWIS, SWIS and other systems. The medium demand projection (EF2) estimates a combined native demand of 257,000 GWh for 2020 which results in the lower LRET target of 26,400 GWh. Assumptions used in this scenario include a lower carbon price trajectory from 2015 through 2023 reflective of the potential for the carbon price to fall after the fixed price period as used in "Reference Case 1".

▪ **Figure 9 Reduction in RET to 20% of demand in 2020**

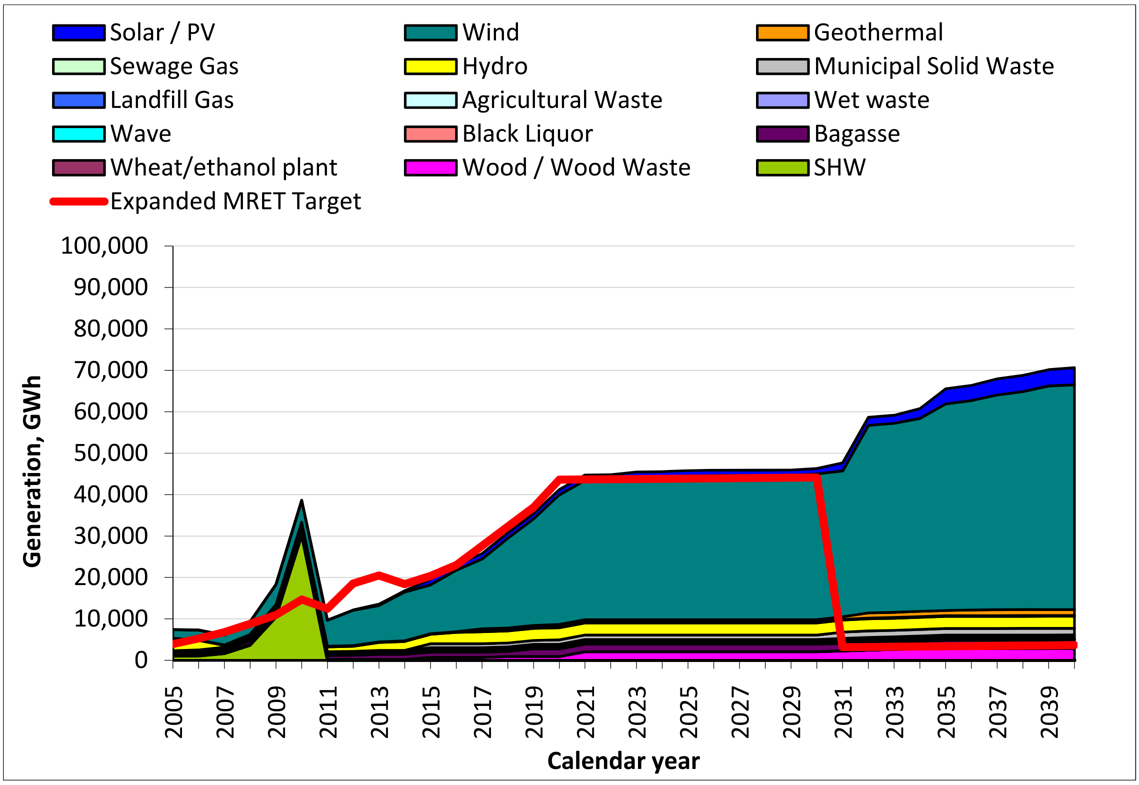


4.1.1. Energy resources

Figure 9 shows that the level of renewable generation required under the "Updated 20% Target" is substantially lower than under "Reference Case 1" (14,600 GWh per annum lower in 2020) and will reduce the incentive to develop more renewable generation in the near term. The modelled contribution of renewable energy resources for the two targets is shown in Figure 10.

▪ **Figure 10 Resource mix to meet the RET ("Reference Case 1" and "Updated 20% Target")**

RET target resource mix – "Reference Case 1"



RET target resource mix – Updated 20% target

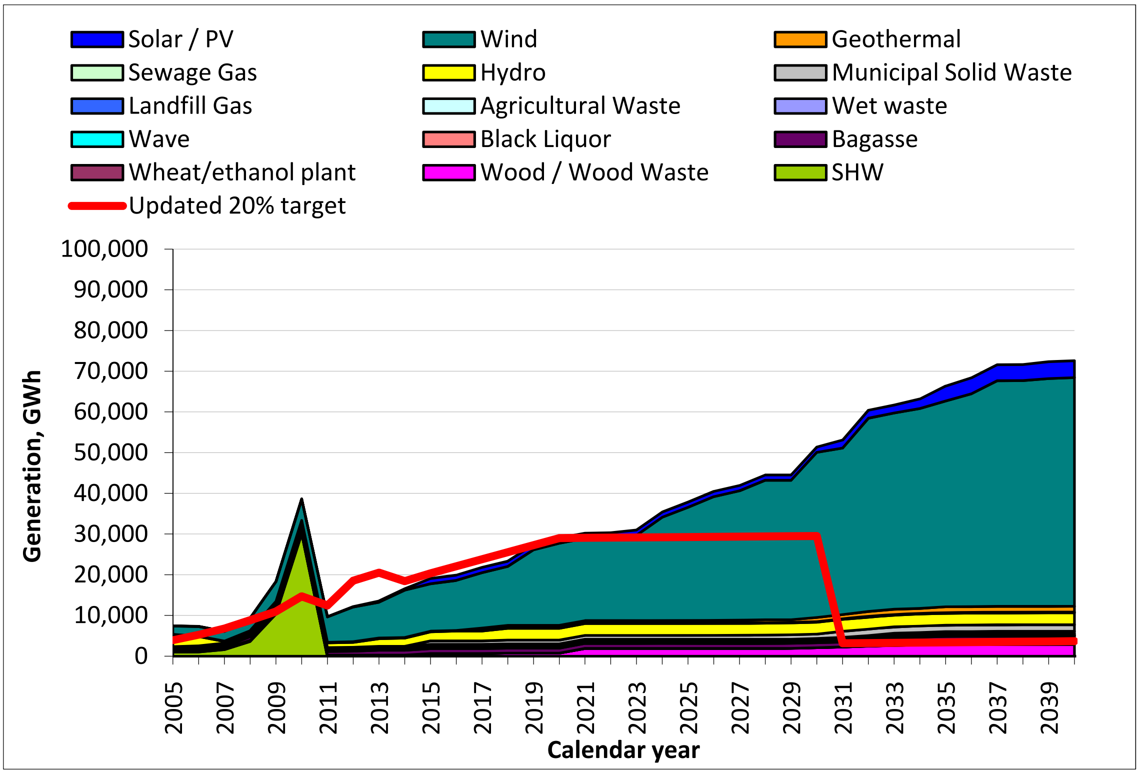


Figure 10 shows the large spike in the SHW and small scale PV uptake due to attractive State based feed-in tariffs and the multipliers historically applied under the RET. Moreover, it illustrates a reduction in the level of renewable generation developed with the “Updated 20% Target” and shows that further renewable generation development is delayed until post 2023 when the carbon price and gas prices are sufficiently high to make new renewable development economically viable. A reduction in wind generation development by 2022 of approximately 4,800 MW (13,400 GWh) accounts for the majority of the difference in renewable generation between the two cases. The figure also illustrates that shortly after 2030 the cumulative level of renewable generation development is similar in both cases. Effectively, the higher target in “Reference Case 1” accelerates the development of renewable generation in the period from 2015 to 2020 and the assumed carbon and gas prices drive development post 2023.

Over the 2013 to 2031 period (financial year ending) the “Updated 20% Target” results in a lower resource cost than “Reference Case 1”. The net present value of the change in resource cost between the two cases is approximately $4.5 billion. This change is driven by the greater levels of renewable generation being developed in “Reference Case 1”. Resource cost reductions associated with less thermal generation in “Reference Case 1” do not offset resource cost increases associated with additional renewable generation.

Based on an estimated reduction of CO_2-e emissions of 119 Mt this change in resource cost would equate to a $38/t cost of additional GHG abatement[7] associated with “Reference Case 1” relative to the “Updated 20% Target”.

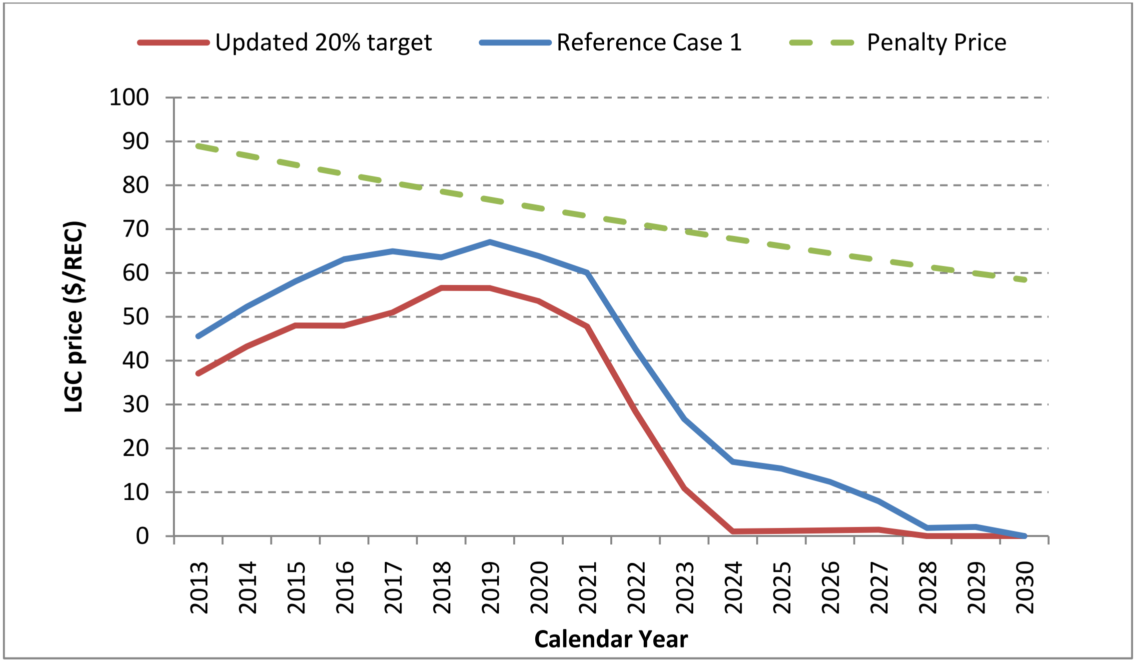
4.1.2. LGC Price

The reduced requirement for renewable energy is reflected in the expected LGC price being noticeably lower under the “Updated 20% Target” as shown in Figure 11. The lower LGC price arises because there is less need for more expensive renewable energy options, and electricity prices are higher due to the marked reduction in the rate of increase of renewable energy generation over the period to 2020. In 2019, when the LGC price is highest in “Reference Case 1”, the difference in LGC price is approximately $10.5/MWh. The chart shows the penalty price trending down in real terms with assumed CPI growth of 2.5% per annum.

---

[7] Cost of abatement is the NPV of resource cost change between the cases divided by the total change in emissions for the period 2013-2031 and is based on the methodology requested by CCA and recommended by DCCEE in (2011) “Estimating the Cost of Abatement”, http://www.climatechange.gov.au/~/media/publications/abatement/20111011-estimating-the-cost-of-abatement-pdf.pdf.

- **Figure 11 Change in LGC prices for "Reference Case 1" and "Updated 20% Target", June 2012 dollars**



Note: the Penalty price[8] is based on $88.9/REC in June 2012 dollars in 2013 allowing for company tax rate of 30%.

The lower LGC price for the "Updated 20% Target" also translates into a lower certificate cost for the RET. By 2020, the certificate cost for "Reference Case 1" is forecast to be $12.8/MWh compared to $6.9/MWh for the "Updated 20% Target". This price is substantially lower for the "Updated 20% Target" due to the lower renewable energy requirement and also the lower LGC price. The price of SRES has been modelled to be $31/MWh[9] nominal on average across the planning horizon, although the SRES costs are the same for both cases so this assumption does not impact on the relative difference between the two cases.

The NPV of certificate costs over the period 2013-2030 (calendar year) for "Reference Case 1" is estimated to be approximately $20.3 billion compared to approximately $12.8 billion for the "Updated 20% Target", a change of approximately 37%. A discount rate of 7% is assumed in determining the NPV.

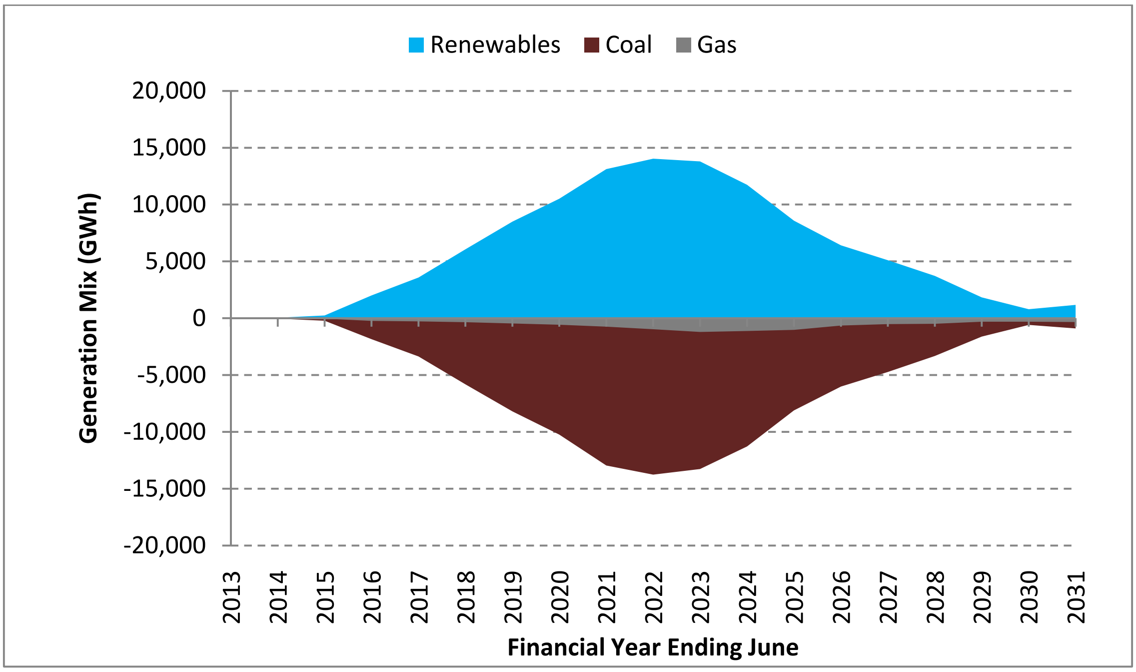
4.1.3. Changes in thermal energy production

The reduced RET requirement under the "Updated 20% Target" results in less renewable development (primarily wind) and more generation from existing coal-fired power stations. Figure 12 illustrates the difference in energy production from coal, gas and renewable generators between the "Reference Case 1" and the "Updated 20% Target".

8 The Penalty price is in nominal dollars currently set at $65/REC, hence the fall in real terms shown in Figure 11

9 This price is based on historical prices and an expectation that SRES prices will be below the $40 Clearing House price.

▪ **Figure 12 Differences in generation ("Reference Case 1" minus "Updated 20% Target")**

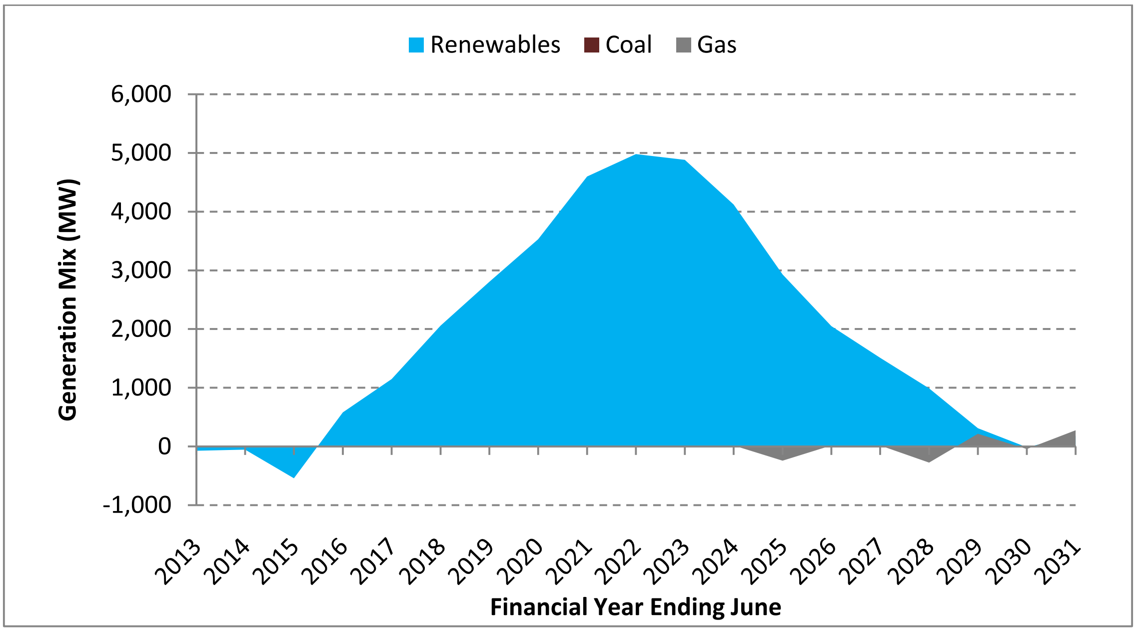


It should be noted that, as Figure 12 displays the differences between two alternate RETs, the displacement of coal and gas generation in the "Updated 20% Target" case would still be significant when compared to the "No RET" case (see section 4.2).

The majority of the reduction in generation in "Reference Case 1" comes from black coal, with a maximum decrease of approximate of 9,500 GWh by 2022 (i.e. 8.0% reduction), while brown coal generation decreased by a maximum of approximately 4,200 GWh (i.e. 9.7% reduction) when compared to the "Updated 20% Target".

Figure 13 illustrates the additional investment that occurs under "Reference Case 1", compared to the "Updated 20% Target". At its peak in 2022, approximately 5,000 MW of additional renewable generation is developed under "Reference Case 1" compared to the "Updated 20% Target". However by 2030 the difference in overall renewable generation capacity between the two cases is minimal.

- **Figure 13 Change in capacity ("Reference Case 1" minus "Updated 20% Target")**



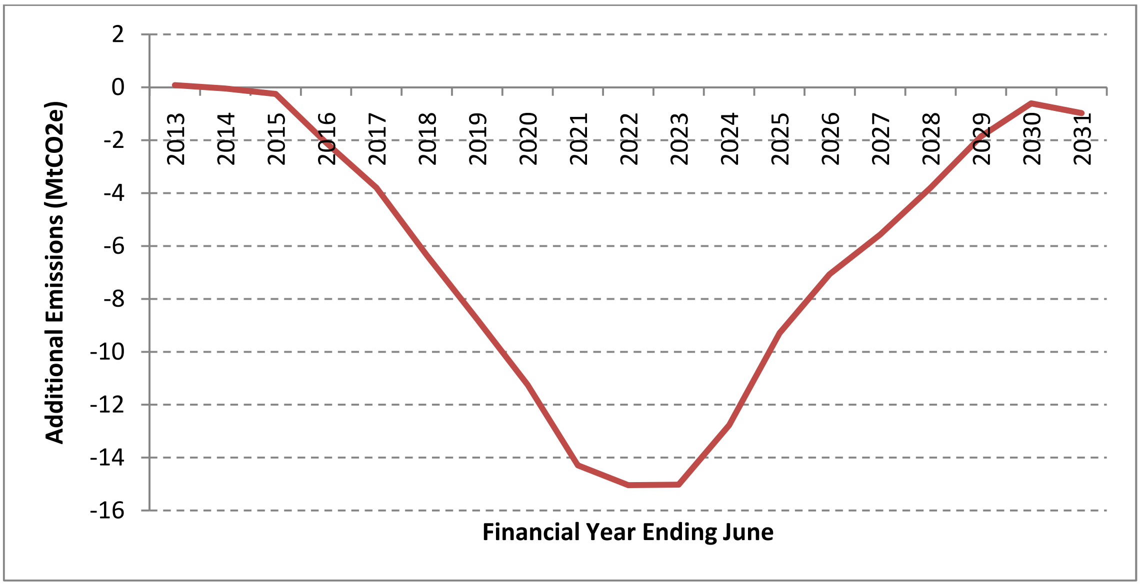
Minor differences are expected in the required timing of new gas-fired peaking plant between cases, with peaking plant required slightly earlier in the "Updated 20% Target" case where there is less renewable generation capacity. However, generally, there is little or no need for investment in new gas-fired generation over the next 10 years since demand growth is met by increases in renewable generation under both cases. By around 2023 supply and demand are in balance again, raising electricity prices and encouraging new entry.

4.1.4. Greenhouse gas emissions reduction

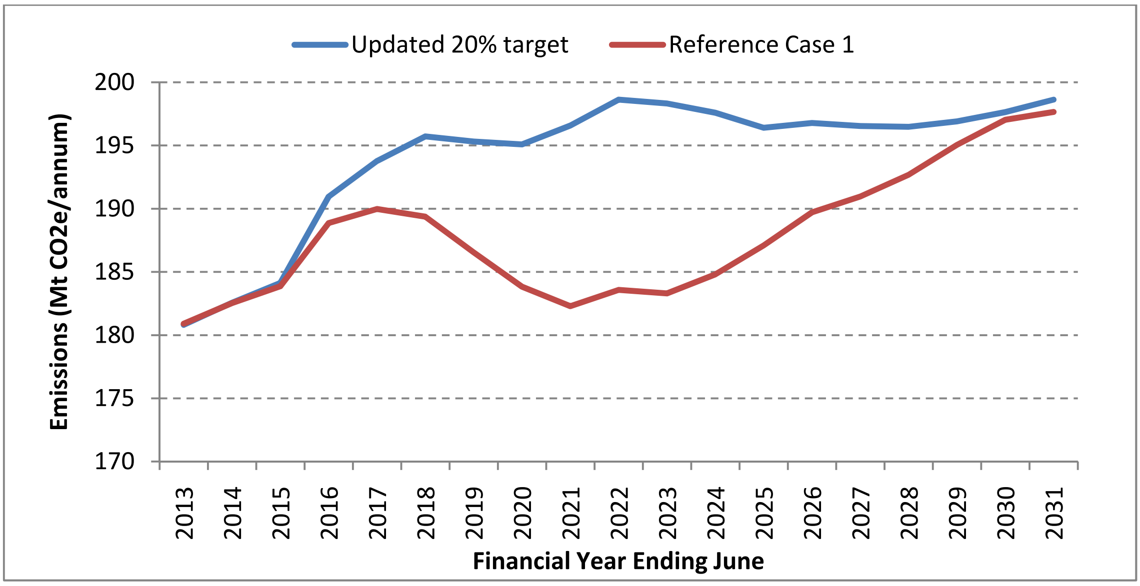
The impact on emissions from the change in generation development is shown in Figure 14. "Reference Case 1" brings forward more renewable energy, offsetting coal fired generation and providing a reduced level of emissions system wide of approximately 119 Mt by 2030/31. The reduced difference post 2023 reflects renewable generation starting to be developed in the "Updated 20% Target" case as the carbon price reaches a level that encourages the next lowest cost technologies/projects to come into the market (predominantly wind).

Over the period 2013-2031 the total emissions are 3,570 MtCO_2e for "Reference Case 1" and 3,689 MtCO_2e for the "Updated 20% Target", indicating a potential net reduction in total emissions of approximately 119 Mt under the "Updated 20% Target". Figure 15 compares the two emission profiles.

- **Figure 14 Difference in GHG emissions ("Reference Case 1" minus "Updated 20% Target")**



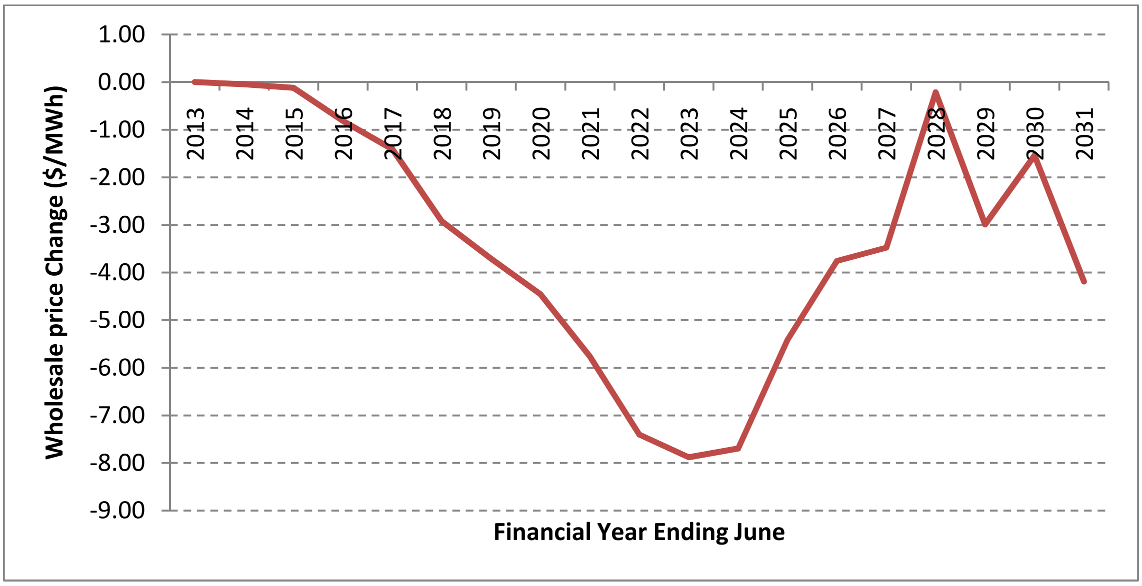
- **Figure 15 Comparison of carbon emissions for "Reference Case 1" and "Updated 20% Target"**



4.1.5. Wholesale price

The greater development of renewable generation in “Reference Case 1” is expected to put downward pressure on wholesale prices due to the extra supply of low (or zero) marginal cost energy which enters the market and is in excess of incremental changes in demand. Figure 16 shows the change in the volume weighted average wholesale prices across all regions in Australia when the two scenarios are compared. A negative price in this figure indicates that oversupply from “Reference Case 1” leads to lower electricity prices than expected in the “Updated 20% Target” case. The “Updated 20% Target” would potentially increase wholesale energy prices by up to $7.8/MWh by 2023.

▪ **Figure 16 Wholesale price decrease with “Reference Case 1”, June 2012 dollars**



The narrowing of the gap in wholesale prices post 2023 is due to the increased development of renewable energy under the “Updated 20% Target”, which is influenced by the increasing gas price and the increasing carbon price. The adverse price impact of the reduced RET is noticeable but not permanent.

The price volatility after 2026 is due to slight differences in timing between investment in new generation between the two scenarios. The average price change in this period from 2026 to 2031 is in the order of $-2.7/MWh.

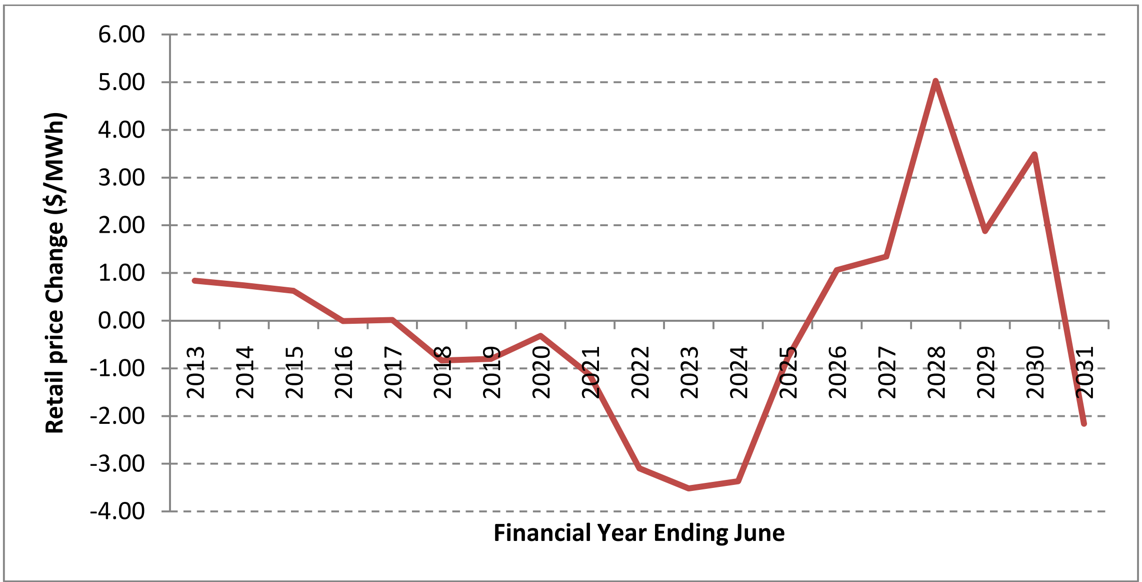
4.1.6. Retail price

Wholesale and LGC price changes also impact on residential retail prices. Figure 17 illustrates the impact on the residential retail prices across Australia (i.e. volume weighted retail price across all regions). This chart indicates that there is a minor impact of a change in the RET schemes on the retail sector and end consumers, with prices largely higher under the “Updated 20% Target” in the first 10 years, but lower after 2025. This is due to the higher wholesale price with the “Updated 20% Target” being only partially offset by the lower certificate cost in the years to 2023. However, as demand and supply become more balanced and wholesale prices recover in “Reference Case 1”, the difference in wholesale prices between the two cases become negligible. Then, the lower certificate cost under the “Updated 20% Target” starts to dominate leading to lower retail prices.

The differences in retail prices are small compared to the actual retail prices. For example, the expected retail price in 2022 is estimated to be 24.9 cents/kWh compared to the potential 0.31 cents/kWh increase with the “Updated 20% Target”. That is, a change in retail prices of just over 1.2% is anticipated in 2022, and this is the largest percentage change in the first 10 years of the planning horizon.

The impact on a standard residential retail price is shown in Figure 17.

- **Figure 17 Retail price difference between “Reference Case 1” and “Updated 20% Target”**



The change in retail prices translates into a modest impact on the average household bill over time. For example, the price variation results in an average $0.4/annum higher retail bill over the 2013-2031 period for the “Updated 20% Target” case. This equates to a NPV increase of $9/household over the 2013 to 2031 period for the “Updated 20% Target”. For all cases, it has been assumed that the average household consumption is 7 MWh/annum.

4.1.7. Summary of Impact

The overall impact of reducing the RET as modelled in the “Updated 20% Target” is that although retail energy prices would initially be lower with “Reference Case 1”, over the medium term retail prices would be lower in the “Updated 20% Target” case. This is due to the impact of the differences between forecast RET certificate costs and the forecast wholesale prices in the two cases. The “Updated 20% Target” is likely to result in higher wholesale prices over the period considered. This increase is partially offset by the lower RET certificate cost. Consequently, the net impact on the average household bill is a slight increase under the “Updated 20% Target” (less than $0.4/annum over the period considered).

The “Updated 20% Target” results in less investment in renewable generation before 2022 (i.e. approximately 14,500 GWh) but as both the carbon price and gas prices increase post 2023, the difference in renewable generation investment narrows compared with “Reference Case 1”.

The lower amount of renewable generation arising from the “Updated 20% Target” results in a potential increase in carbon emissions of 119 Mt over the period to 2031, and delays the transition to a lower emission electricity supply system. This is predominantly due to a continuation of black coal and brown coal generation which is reduced in “Reference Case 1” by almost 9,500 GWh for black coal and up to 4,200 GWh for brown coal over the period to 2022.

The “Updated 20% Target” has a $4.5 billion lower resource cost due to the reduction in renewable capacity being built.

4.2. Impact of abolishing the RET

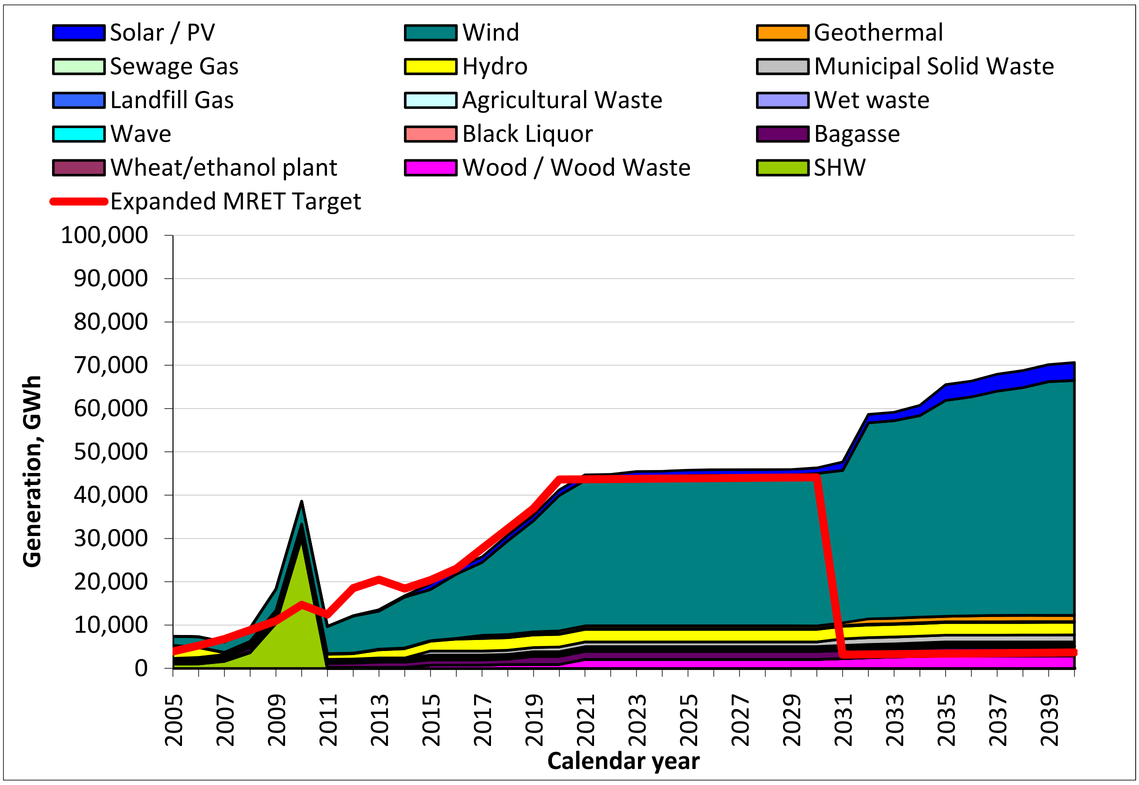
In the “No RET” case it is assumed the RET will cease on 1st January 2013. For modelling purposes a zero target has been assumed from 2013. All committed renewable energy projects are assumed to proceed as planned. The results of this section compare “Reference Case 1” with this “No RET” case. In this case the SRES is also assumed to cease and hence there would be no on-going liability post 2012.

4.2.1. Energy resources

The modelled contribution of renewable energy resources for the two targets is shown in Figure 18.

- **Figure 18 Resource mix “Reference Case 1” compared with “No RET”**

RET target resource mix – ”Reference Case 1”



RET target resource mix – “No RET”

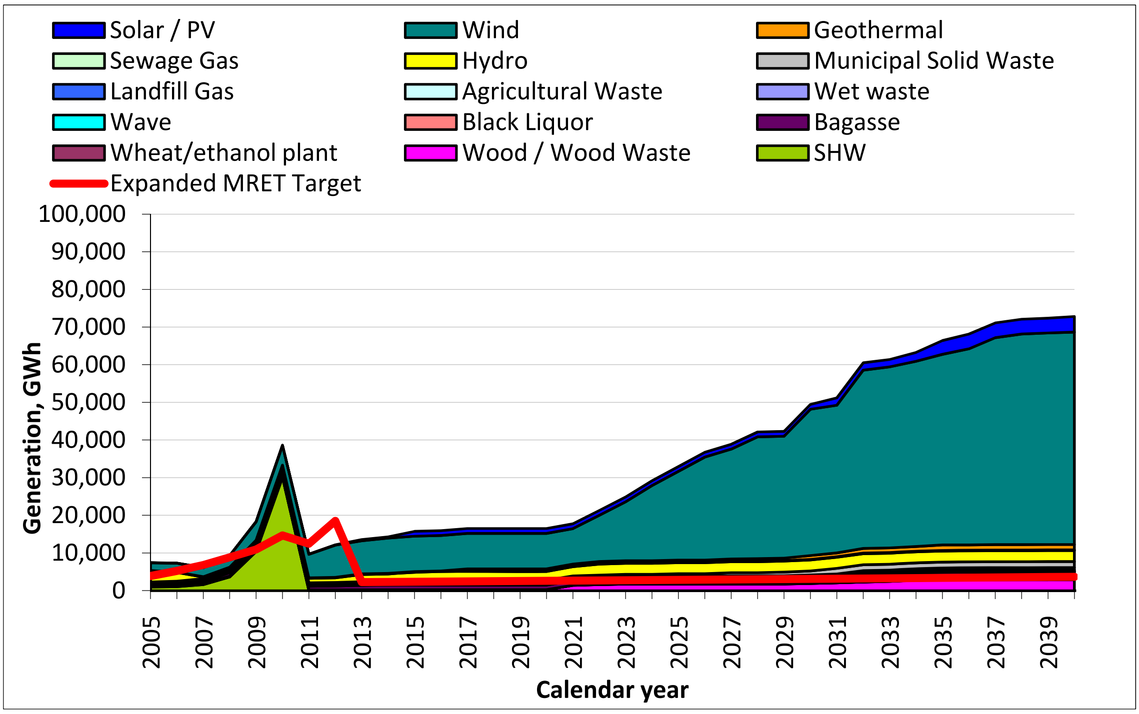


Figure 18 illustrates a reduction in the level of renewable generation developed (nearly 21,500 GWh reduction in wind alone) with “No RET”. Further renewable generation development is delayed until approximately 2023 when the carbon price is sufficient to make some renewable generation economically viable without a renewable energy target.

Over the 2013 to 2031 period, the “No RET” case yields a lower resource cost relative to “Reference Case 1”. The net present value of the change in resource cost between the two scenarios is approximately $8.6 billion. This reduction is driven by capital deferral of renewable generation in the “No RET” and only modest changes to investment in thermal generation.

Based on an estimated reduction in CO_2.e emissions of 217 Mt over the planning horizon to 2031, this would equate to a $40/t cost of abatement associated with “Reference Case 1” when compared against “No RET”.

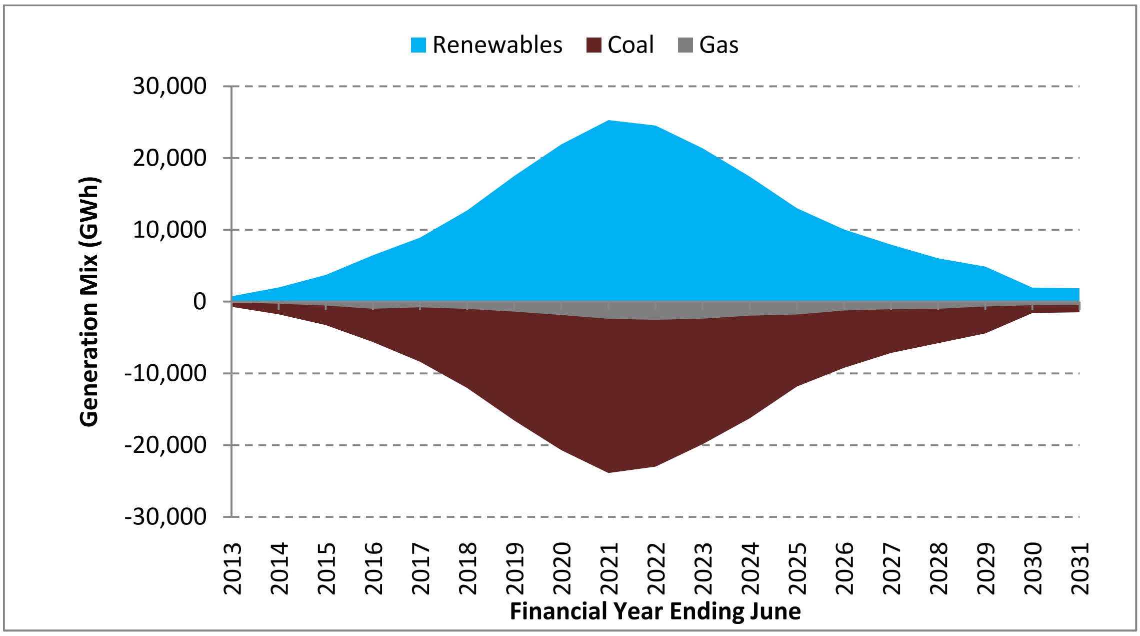
4.2.2. LGC Price

As there is no target post 2012 there is no LGC price or SRES price. It is assumed that all current costs or obligations associated with the RET will not continue in the “No RET” case. The change in certificate cost under the “No RET” case equates to approximately $12.8/MWh by 2020.

4.2.3. Changes in thermal energy production

Removing the RET from 2013 onwards results in less renewable development (primarily wind) and more coal-fired generation as can be seen in Figure 19 which illustrates the difference in energy production from coal, gas and renewable generators between the two scenarios. In Figure 19, positive values indicate greater generation under “Reference Case 1” than under “No RET”. It should be noted that with “No RET”, renewable generation development post 2023 is expected to increase at a greater rate than with “Reference Case 1.

- **Figure 19 Difference in generation – (“Reference Case 1” minus “No RET”)**

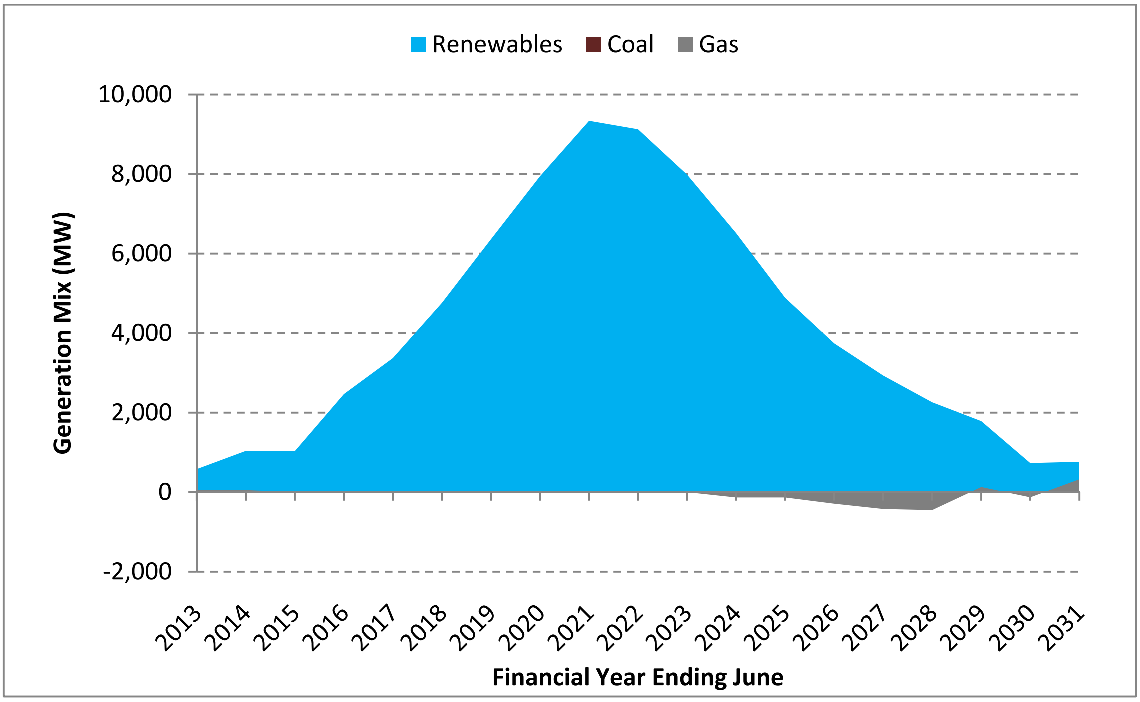


Compared to the “No RET” case, “Reference Case 1” leads to a reduction of approximately 7,100 GWh, or 16.4%, in brown coal generation in 2022 and a 16,000 GWh, or 13.2%, in black coal generation.

A similar comparative result is forecast for capacity increments. Figure 20 illustrates the likely additional capacity required in “Reference Case 1” from 2013 onwards. Due to the recently lowered long term forecasts for electricity demand, and expectation that new thermal generation capacity is unlikely to be required for some time, there is minimal change to the additional thermal capacity required between “Reference Case 1” and the “No RET” case. The amount of renewable energy capacity delayed, as a result of removal of RET, peaks at approximately 9,000 MW in 2021.

The additional renewable generation developed in “Reference Case 1” defers the need for investment in new gas-fired peaking plant from 2025 albeit for only a few years. By 2031, as carbon prices increase and more renewable generation is built, even in the “No RET” case, the difference in requirement for gas-fired peaking plant between the two cases is negligible.

- **Figure 20 Change in capacity – (“Reference Case 1” minus “No RET”)**



4.2.4. Emissions reduction

The expected increase in emissions from “No RET” is temporary, with a delay of 15 years for most of the abatement as shown in Figure 22. The reduced difference towards 2030 is driven by development of renewable generation becoming viable post 2023 when the assumed carbon and gas prices rise to a level sufficient to induce renewable generation investment despite the lack of any other incentive.

- **Figure 21 Difference in GHG emissions – ("Reference Case 1" minus no future RET)**

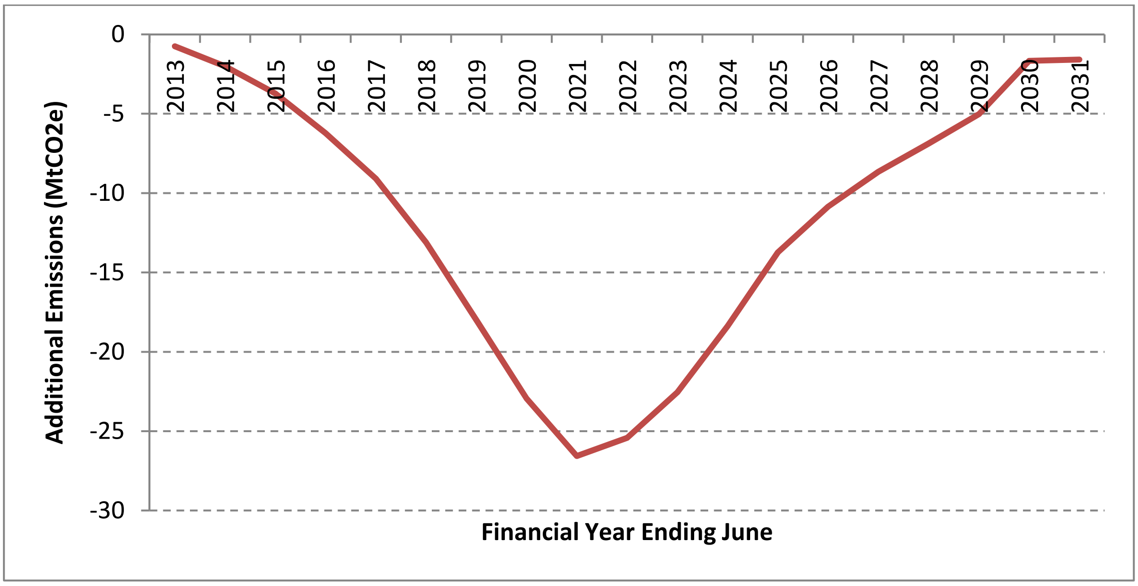
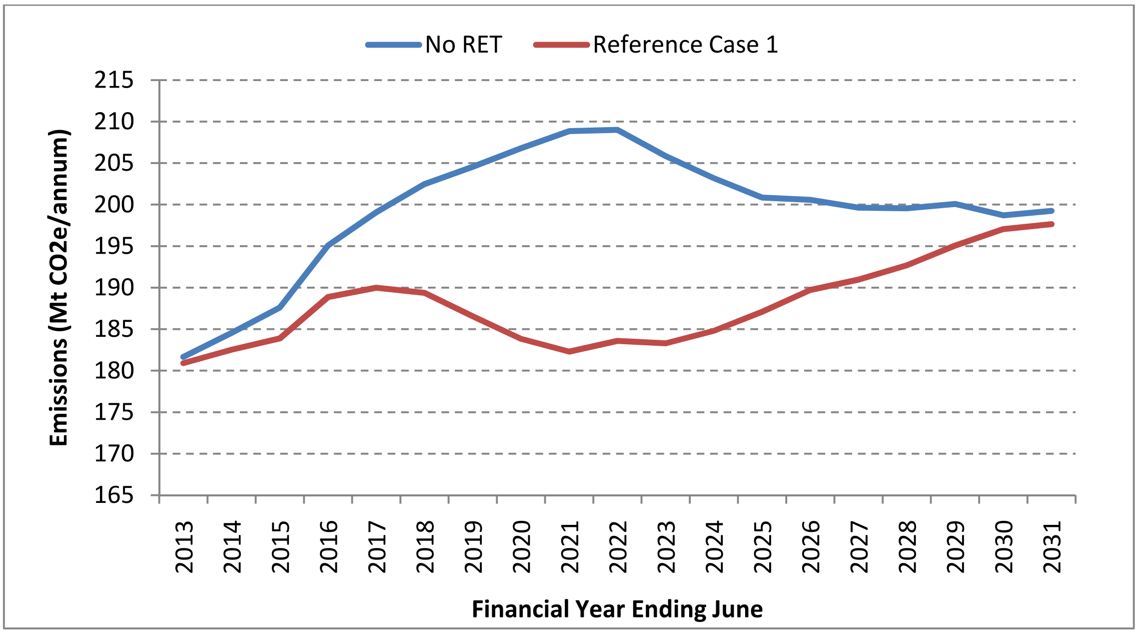


Figure 21 depicts an increasing emission reduction with "Reference Case 1" as more renewable energy is developed offsetting coal fired generation and accelerating a reduction in CO_2e emissions system wide.

Over the period 2013-2031 the total emissions are 3570 MtCO_2e for "Reference Case 1" and 3787 MtCO_2e for the "No RET" case. The removal of the RET is therefore expected to result in a net increase of approximately 217 MtCO_2e compared with "Reference Case 1". A comparison of the two emission profiles is shown in Figure 22.

- **Figure 22 Comparison of carbon emissions for "Reference Case 1" and "No RET"**

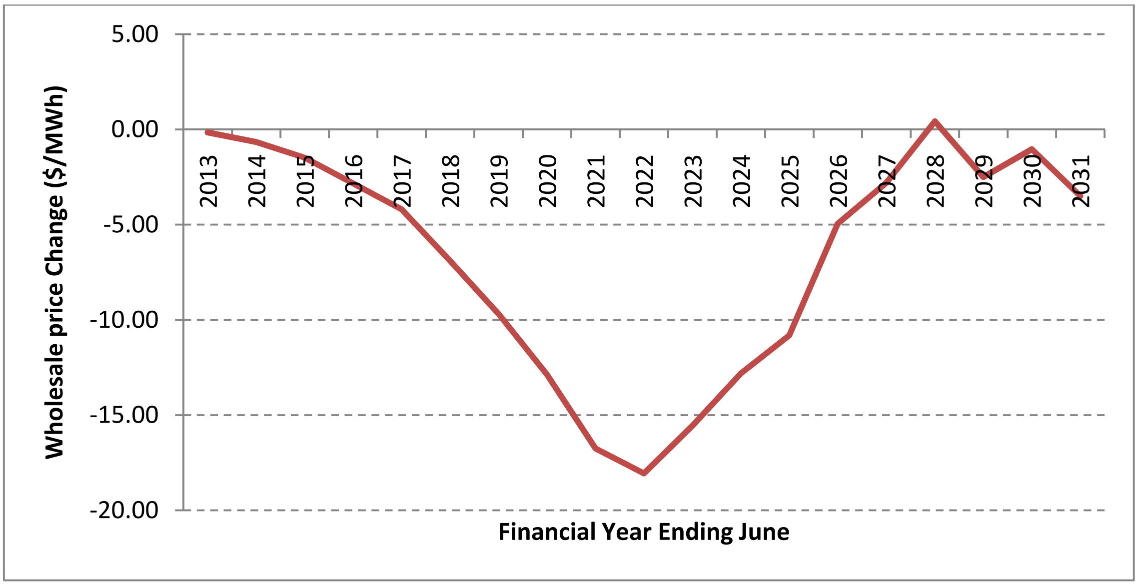


4.2.5. Wholesale price

For "No RET" there is a more balanced supply/demand situation leading to higher prices than in "Reference Case 1". The development of renewable generation in "Reference Case 1" is expected to put downward pressure on wholesale prices due to the extra supply which enters the market in excess of incremental changes in demand. Figure 23 shows the change in the volume weighted average wholesale prices across all regions for the "No RET" case, with the large negative prices indicating a much lower price in "Reference Case 1".

The modelling shows that "No RET" would potentially increase wholesale energy prices by approximately $18.1/MWh by around 2022. There is the potential that, with the low prices in "Reference Case 1", other generators may attempt to change their bidding strategy in order to increase prices and increase their profitability. Changes to bidding strategies to support prices at levels closer to new entry will reduce the differences in wholesale prices observed between these two scenarios.

- **Figure 23 Wholesale price decrease for "Reference Case 1" ("Reference Case 1" minus "No RET"), June 2012 dollars**

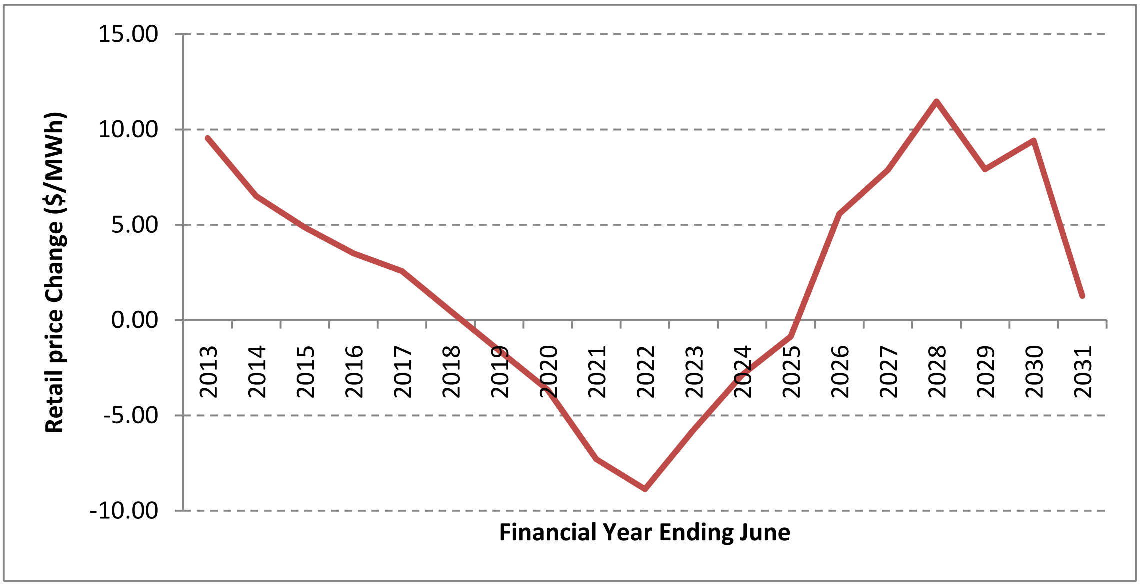


The reduction in price difference post 2023 is driven by renewable development in the "No RET" case once the carbon price increases and gas prices continue to increase. Post 2023 much of the renewable generation developed in the 2013-2020 period in "Reference Case 1" becomes economically viable and will be developed in the "No RET" case. Therefore the expected adverse price impact of the "No RET" case is a delay in renewable development rather than a permanent change in types of generation ultimately developed.

4.2.6. Retail price

Figure 24 illustrates the impact on the residential retail prices across Australia (i.e. volume weighted retail price across all regions) comparing "Reference Case 1" with "No RET". This chart indicates that the change in the RET schemes has a minor impact on retail electricity prices. This is due to the removal of certificate costs from the "No RET" scheme being offset by the higher wholesale prices. In Figure 24, this impact can be seen in the years to 2020 when the retail price is higher in "Reference Case 1", driven by the lower certificate cost under "No RET". This situation changes towards 2020 when the impact of more renewable generation reduces the wholesale price to a greater extent than the increase in certificate cost, leading to a lower retail price in "Reference Case 1". As renewable generation is developed post 2020 in the "No RET" case, the difference in wholesale prices between the two cases reduces and the additional certificate cost under "Reference Case 1" again leads to higher retail prices, although the changes shown are small. In "Reference Case 1", the average increase in retail price is $2.1/MWh over the period which is a 0.8% increase over the "No RET" average retail price for the same period.

- **Figure 24 Retail price change ("Reference Case 1" minus "No RET")**



Assuming average household consumption of 7 MWh per annum, these variations in retail price result in an average reduction in household bill of approximately $15/annum over the 2013 to 2031 in the "No RET" case. This equates to a saving of approximately $154 per household on a NPV basis.

4.2.7. Summary of Impact

With "No RET" it is likely that wholesale prices will be higher over the period considered, however RET certificate costs will disappear and hence retail prices are expected to be lower than in "Reference Case 1". The lower average retail price is reflected in lower average household bills for the "No RET" case.

With "No RET", renewable generation development is over 25,000 GWh or approximately 9,000 MW lower than "Reference Case 1" at its peak around 2021. However, the assumed carbon and gas price increases, narrows the gap in renewable generation development, with only a small difference in renewable generation by 2031.

Less renewable generation in the "No RET" case drives more black and brown coal generation. The change in coal generation has a greater impact on black coal generation. "Reference Case 1" has a maximum black coal reduction of 16,000 GWh, or 13.5%, by 2021, while brown coal reduced by a maximum of 7,900 GWh, or 18.1%. The change in generation mix results in approximately 217 Mt of additional carbon emissions over the period to 2031 in the "No RET" case, delaying the transition to a lower emission electricity supply system.

The "No RET" case has a lower resource cost due to the substantial reduction in renewable capacity being built in the medium term. The NPV of resource cost saving under the "No RET" case compared to "Reference Case 1" is approximately $8.6 billion for the period 2013-2031.

4.3. Combining LRET and SRES

In the "Combined LRET & SRES" case, targets were recombined into a single 45,000 GWh target. The analysis for this case used a model to examine the SRES development as well as a model to estimate LRET development. The latter used the difference between the 45,000 GWh and the SRES development to estimate the uptake of large-scale renewable generation required to meet the target, and the associated LRET price. The SRES model was re-run based on the new LRET price, and iteration between the LRET and SRES model continued until a stable solution was achieved. This iterative approach resulted in a stable SRES target (i.e. within a few hundred GWh) in the order of 10,500 GWh by 2020.

This modelling approach resulted in a LRET target of 37,000 GWh by 2020. In this section, this lower target is compared against the existing 41,000 GWh target and the impact on certificate cost is discussed.

4.3.1. Energy resources

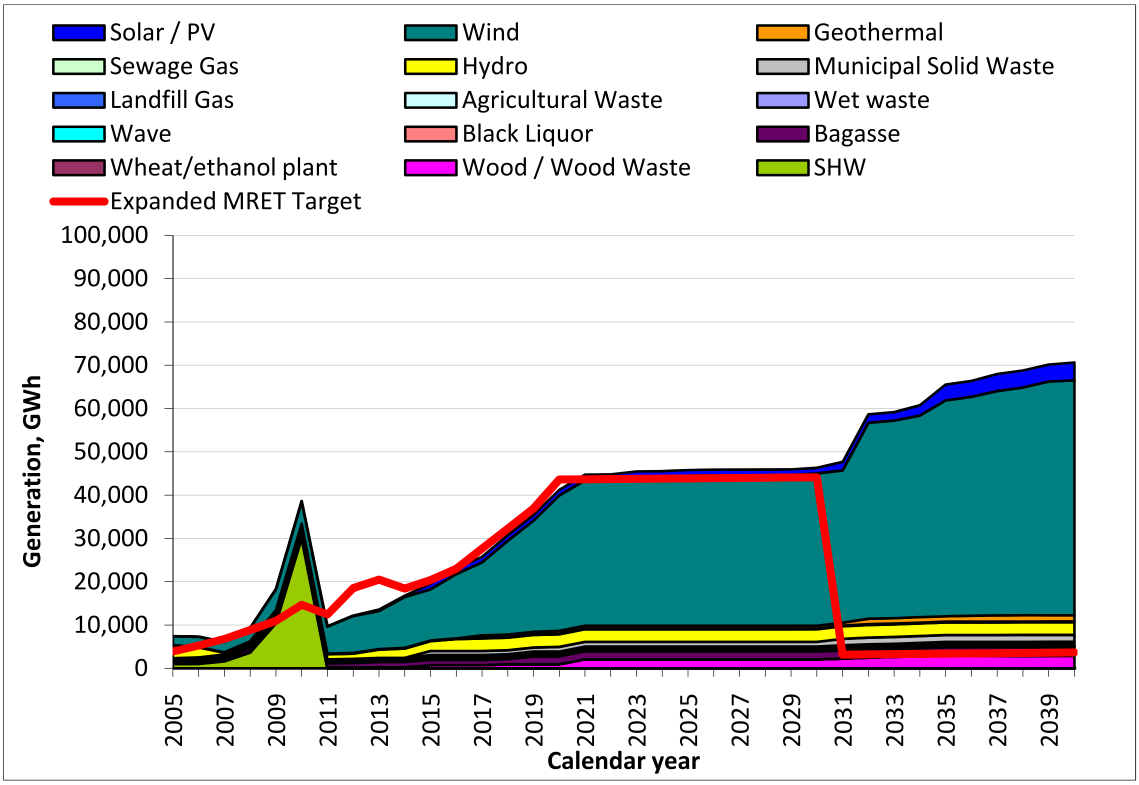
The modelled contribution of renewable energy resources for the two targets is shown in Figure 25. The level of renewable generation required under a "Combined LRET & SRES" case is marginally lower resulting in a slight reduction in renewable generation development in the near term. Further renewable generation development is delayed until approximately 2025 when the carbon price is sufficient to initiate additional renewable generation development.

Over the 2013 to 2031 period a slightly lower resource cost would result from the "Combined LRET & SRES" case. The net present value of the change in resource cost between the two cases is approximately $2.4 billion less for the "Combined LRET & SRES" case. This change is driven by more renewable generation being developed in "Reference Case 1".

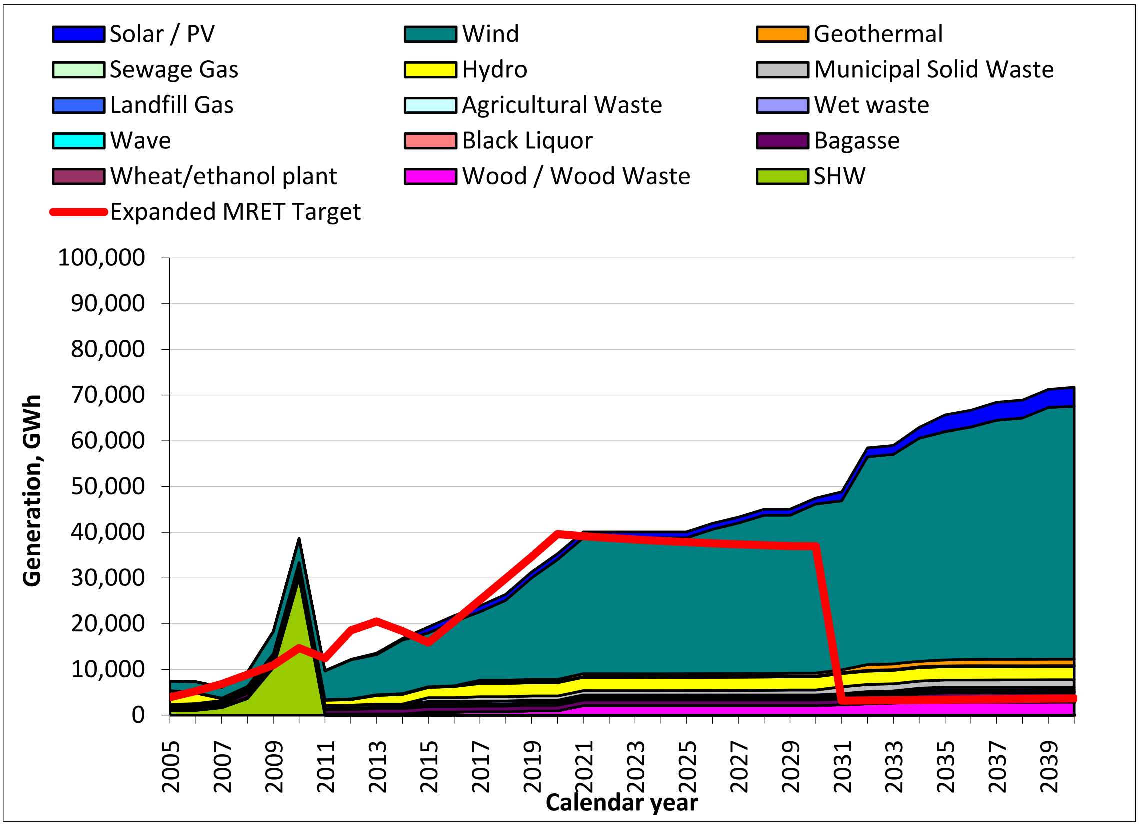
Based on an estimated reduction of emissions of 68 Mt the estimated cost of emissions associated with moving to the "Combined LRET & SRES" is $35/t.

■ **Figure 25 Resource mix to meet the RET ("Reference Case 1" and "Combined LRET & SRES")**

RET target resource mix – "Reference Case 1"



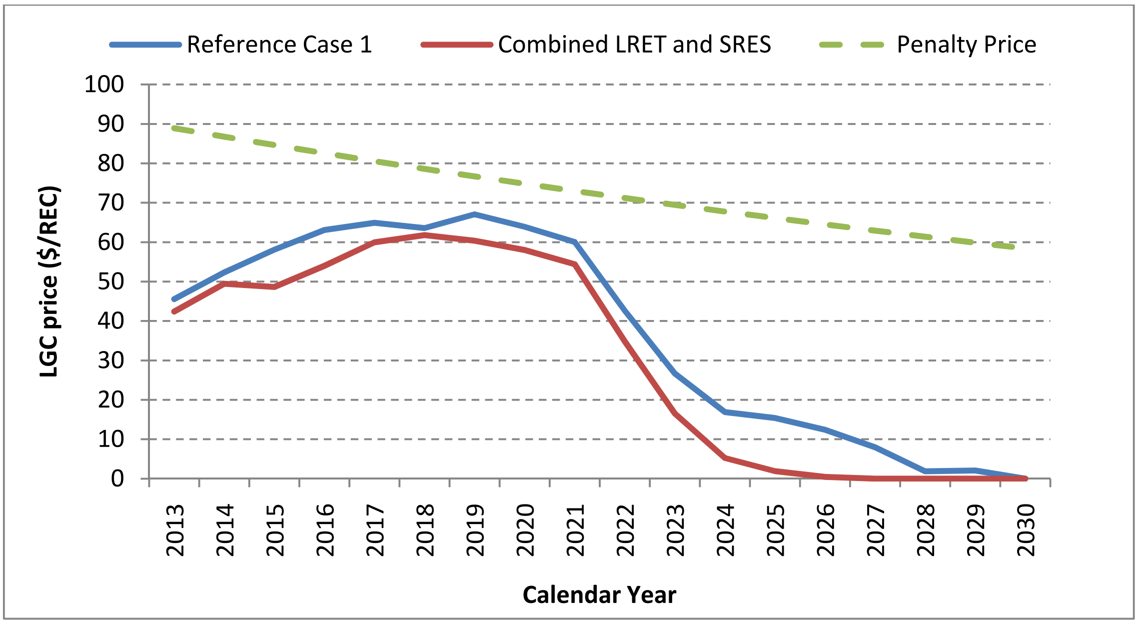
RET target resource mix – "Combined LRET & SRES"



4.3.2. LGC Price

Figure 26 illustrates that the slightly reduced demand for renewable energy in the "Combined LRET & SRES" results in the expected LGC price being approximately 9% lower than "Reference Case 1" by 2020.

▪ **Figure 26 Change in certificate price with "Combined LRET & SRES", June 2012 dollars**



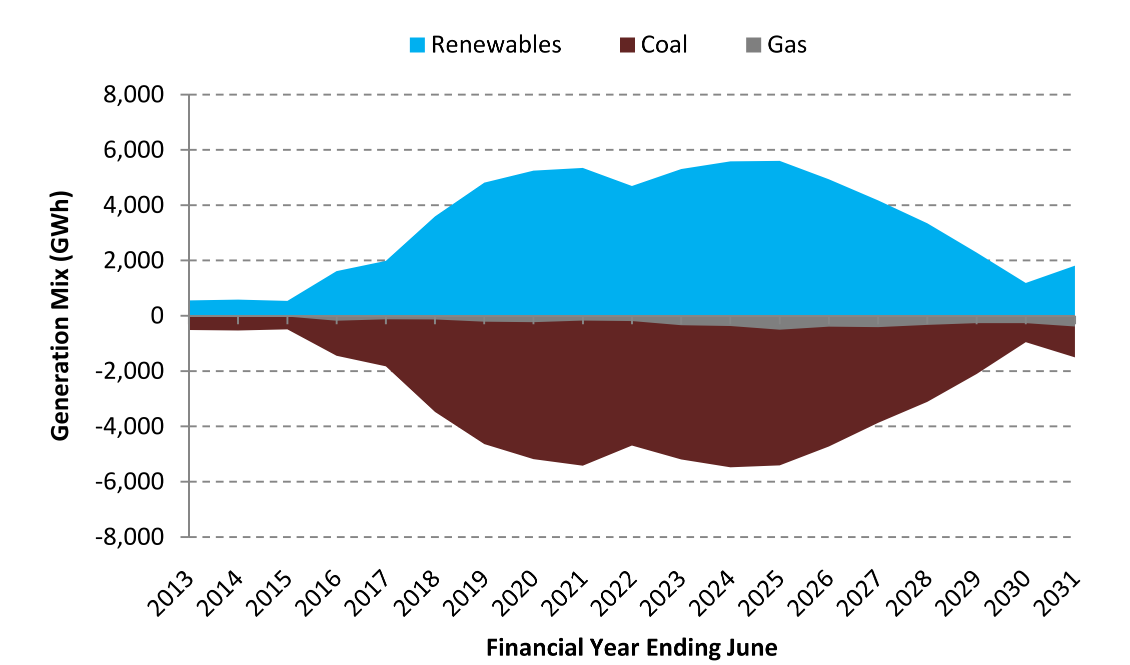
While there is a lower LGC price, the price for the SRES component increases. Under "Reference Case 1", an average price of $31/MWh nominal is assumed for the SRES component whereas in the "Combined LRET & SRES" the same small-scale renewable generation can receive the higher LGC price. Therefore, the total certificate cost is similar between the two cases. In 2020, the certificate cost for "Reference Case 1" peaks at $12.8/MWh compared to $12.3/MWh for the "Combined LRET & SRES".

4.3.3. Changes in thermal energy production

The level of renewable development by 2020 in the "Combined LRET & SRES" case is approximately 5,400 GWh less than under the "Reference Case 1", with wind generation being replaced by existing coal-fired generation as shown in Figure 27. In the "Combined LRET & SRES", up to 3,500 GWh of additional black coal generation is required by 2020 (i.e. 2.9% increase compared to "Reference Case 1"), while approximately 1,700 GWh of additional brown coal generation is required (i.e. 3.8% increase compared to "Reference Case 1").

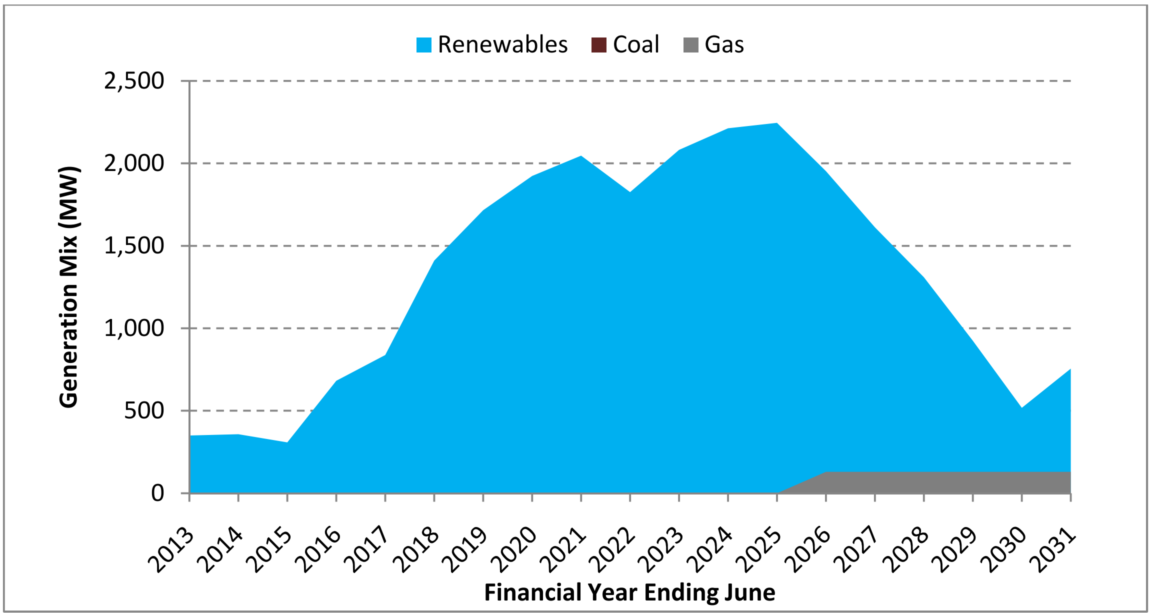
The deficit in renewable development between the cases starts to reduce when the carbon price and gas prices have increased enough to drive more renewable development in the "Combined LRET & SRES".

▪ **Figure 27 Difference in generation – ("Reference Case 1" minus "Combined LRET & SRES")**



Approximately 2,000 MW of renewable generation capacity is deferred under the "Combined LRET & SRES", as illustrated in Figure 28. The amount of additional thermal generation in either case is minimal due to the lower demand now expected.

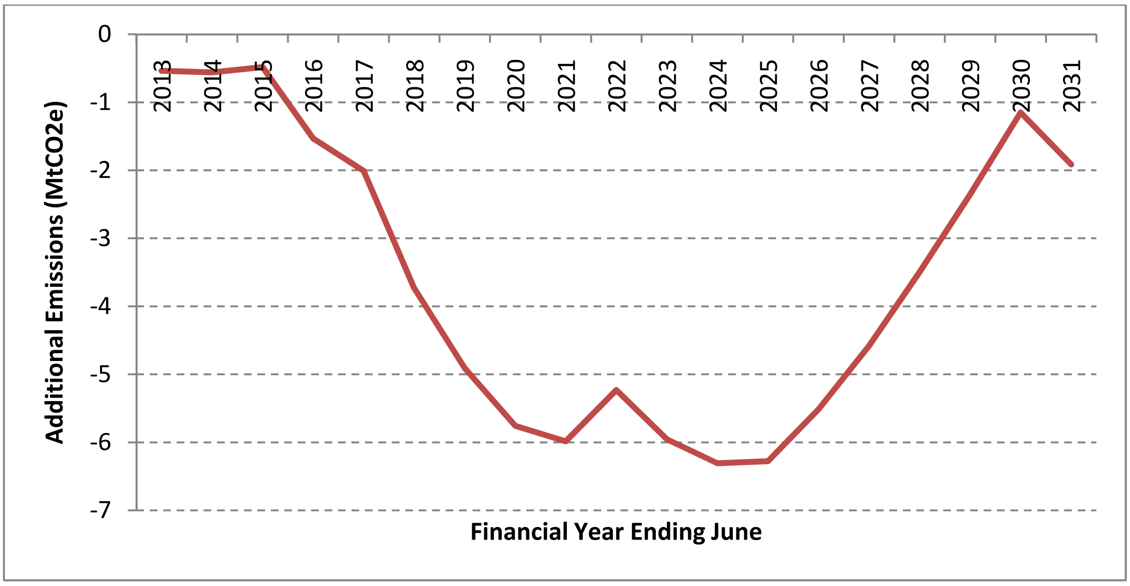
▪ **Figure 28 Change in capacity – ("Reference Case 1" minus "Combined LRET & SRES")**



4.3.4. Emissions reduction

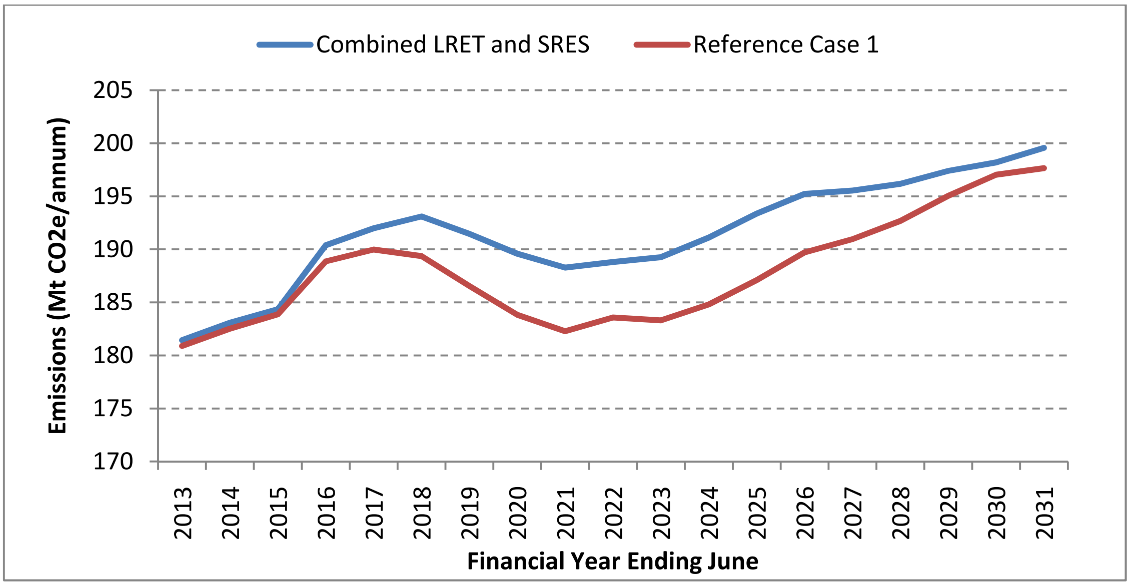
The additional emission abatement arising from "Reference Case 1", relative to the "Combined LRET & SRES", is shown in Figure 29. "Reference Case 1" encourages more renewable energy offsetting coal fired generation and providing a reduced level of emissions system wide. The potential change in CO_2e emission production is temporary and the scenarios converge again once renewable developments become viable.

- **Figure 29 Difference in GHG emissions – ("Reference Case 1" minus "Combined LRET & SRES")**



Over the period 2013-2031 the total emissions are 3,570 $MtCO_2e$ for "Reference Case 1" and 3,638 $MtCO_2e$ for the "Combined LRET & SRES", therefore the "Combined LRET & SRES" results in a potential net increase in emissions of approximately 68 Mt. A comparison of the two emission profiles is shown in Figure 30.

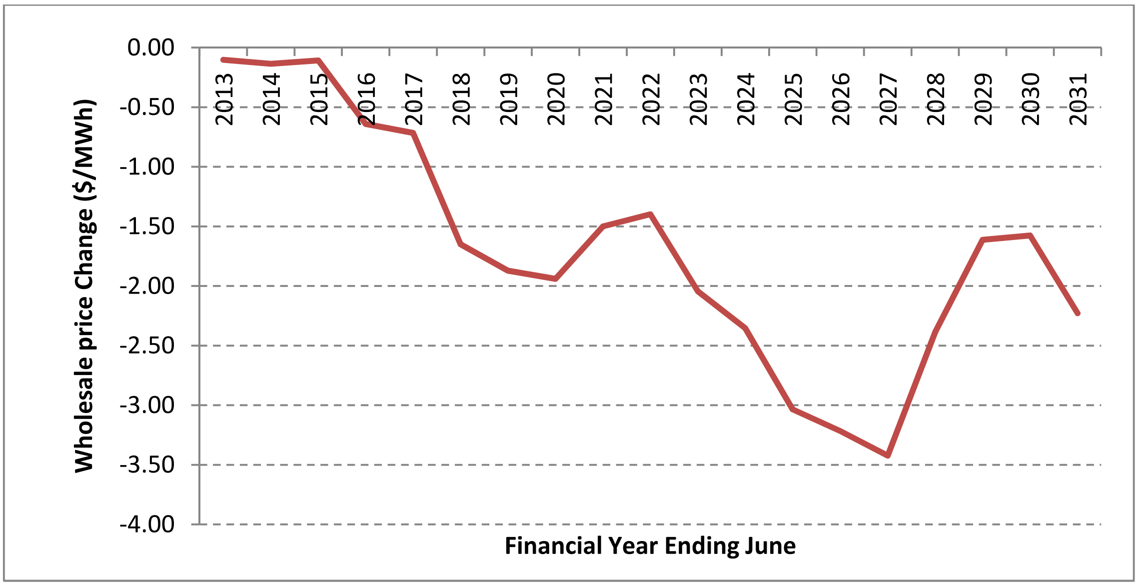
- **Figure 30 Comparison of carbon emissions for "Reference Case 1" and the combined target**



4.3.5. Wholesale price

The development of additional renewable generation in "Reference Case 1" is estimated to put only slight downward pressure on wholesale prices relative to the "Combined LRET & SRES", and the overall impact on wholesale energy prices is marginal. Figure 31 shows the expected change in the volume weighted average wholesale prices across all regions for the "Combined LRET & SRES", with the small negative prices indicating a lower price with "Reference Case 1".

- **Figure 31 Wholesale price increase ("Reference Case 1" minus "Combined LRET & SRES"), June 2012 dollars**



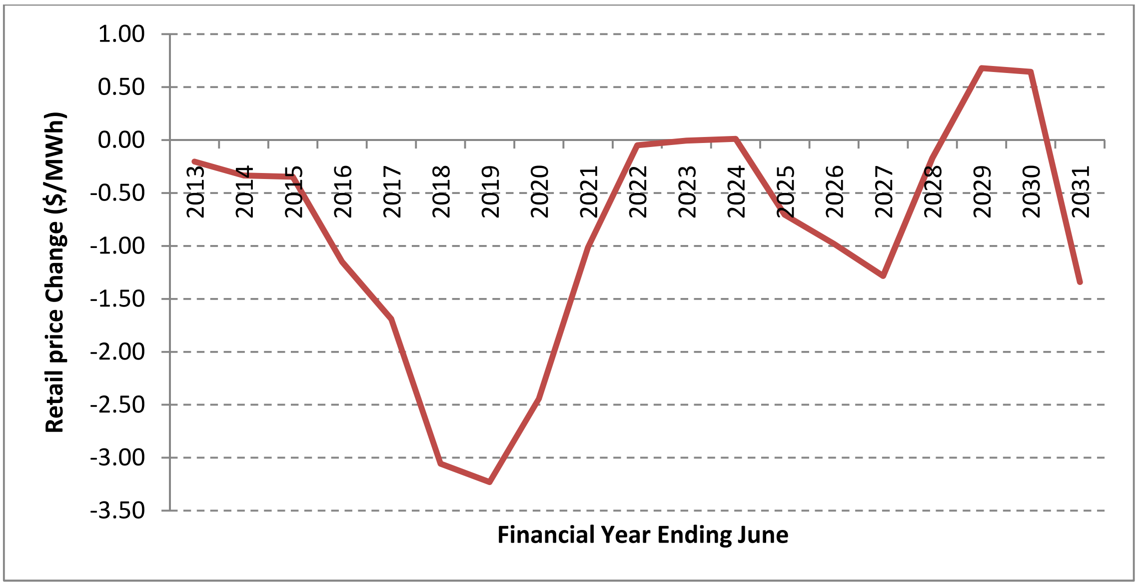
Any adverse price impacts of the "Combined LRET & SRES" are not expected to be large or permanent.

4.3.6. Retail price

The impact on wholesale prices is reflected in the residential retail prices, along with the marginally higher certificate cost. Figure 32 illustrates the expected impact on the residential retail prices across Australia (i.e. volume weighted retail price across all regions). The lower initial price under "Reference Case 1" is due to a lower wholesale price and marginally lower certificate cost. In the "Combined LRET & SRES", the certificate cost is higher, as both large and small scale renewable generation are priced at the LGC price of approximately $50/MWh on average from 2013 to 2020, whereas under "Reference Case 1", the small-scale renewable generation was priced at approximately $31/MWh nominal. This is reversed after 2020 when it is assumed the certificate cost for the SRES reduces faster in the "Combined LRET & SRES" than in "Reference Case 1". This is driven by the LGC price reducing more dramatically post 2020 than the assumed SRES price in "Reference Case 1".

Over the entire period the change in retail price is expected to be minimal regardless of whether "Reference Case 1" or the "Combined LRET & SRES" is in place. The overall impact on the average household bill is expected to be an average increase compared to "Reference Case 1" of $6/annum. On an NPV basis over the period from 2013 to 2031, "Combined LRET & SRES" increases the average bill by around $70, compared to "Reference Case 1".

- **Figure 32 Retail price change ("Reference Case 1" minus the "Combined LRET & SRES"), June 2012 dollars**



4.3.7. Summary of Impact

While initially lower, average retail energy prices are expected to be very similar when comparing the "Combined LRET & SRES" and "Reference Case 1". Hence the impact on the average household bill is small. This is unsurprising given there is little change in the generation mix over the period considered. While wholesale prices are likely to be lower under "Reference Case 1" the difference is expected to be small (i.e. less than $1.7/MWh).

With the "Combined LRET & SRES" there would be approximately 68 Mt of additional carbon emissions over the period to 2031. This is driven by approximately 5,400 GWh less renewable generation being developed before 2023. This reduction leads to an increase in black and brown coal generation in the order of 3,500 GWh, or 2.9%, and 1,700 GWh, or 3.8% respectively, by 2020.

The "Combined LRET & SRES" is expected to have a lower resource cost due to the reduction in renewable capacity being built. The NPV of resource cost differences is approximately $2.4 billion for the period 2013-2031. This equates to a $35/t cost of emission abatement associated with "Reference Case 1" rather than moving to "Combined LRET & SRES".

4.4. Reference Case 2 – Treasury Core Policy Carbon Price

In this case the "Reference Case 1" target remains the same with the only change in this scenario being a higher carbon price assumed from 2015 to 2023. The analysis uses the CP2 carbon price scenario outlined in Section 3.3.

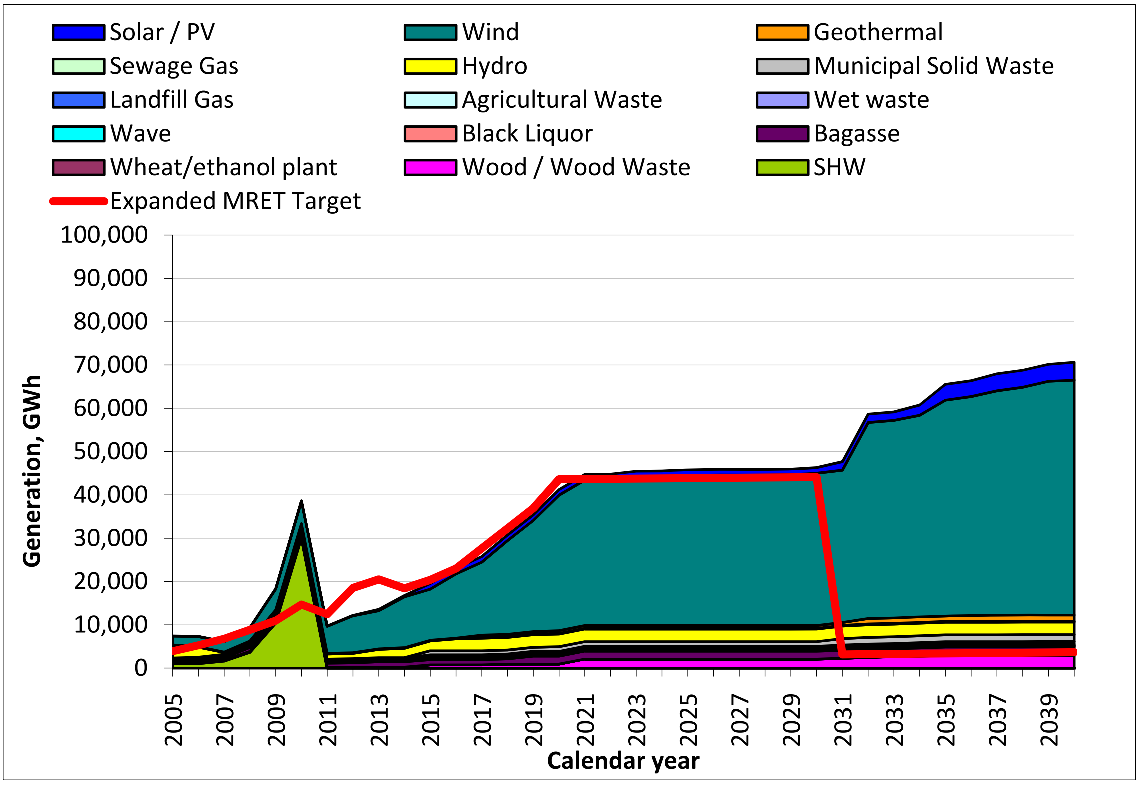
There are no other input assumption differences between these two cases, the medium demand scenario (EF2) is used for both cases.

4.4.1. Energy resources

The modelled contribution of renewable energy resources for the "Reference Case 1" and "Reference Case 2" are shown in Figure 33.

- **Figure 33 Resources mix ("Reference Case 1" and "Reference Case 2")**

RET target resource mix – "Reference Case 1"



RET target resource mix – "Reference Case 2"

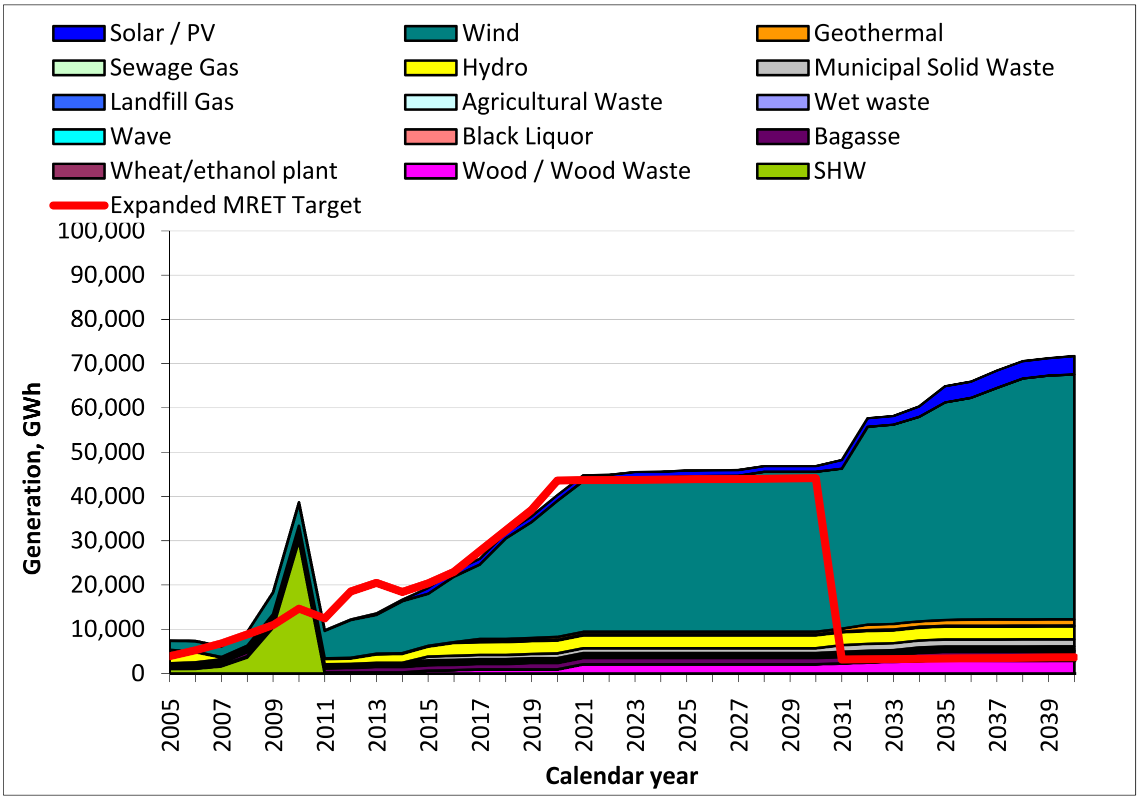


Figure 33 illustrates the expected level of renewable generation under both cases is very similar. There is a marginal change in timing of renewable energy development with "Reference Case 2" driving slightly more development in renewable generation in the shorter term.

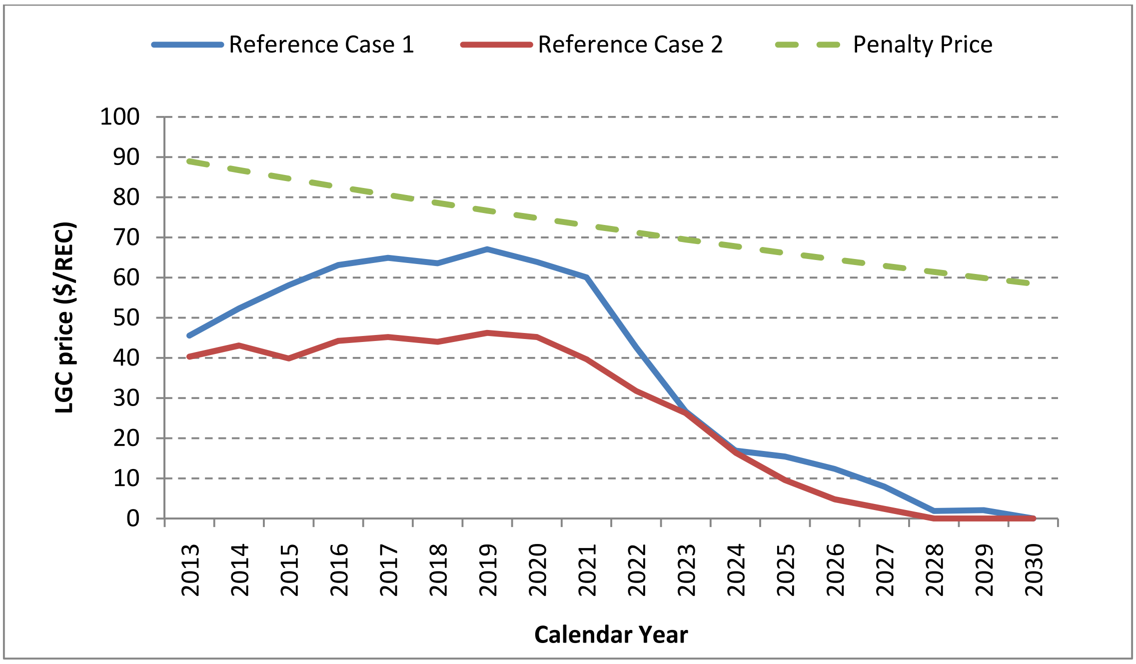
Over the 2013 to 2031 period, "Reference Case 2" leads to a higher resource cost. With no additional renewable development over the period, the main change in resource cost is due to a change in coal and gas generation driven by the higher carbon price. The NPV of the resource cost is approximately $437 million greater in "Reference Case 2".

Based on an estimated reduction of emissions of 12 Mt this equates to a $36/t cost of emissions associated with "Reference Case 2".

4.4.2. LGC Price

Since the demand for renewable generation is the same in these two scenarios, changes in LGC price are driven by higher wholesale prices in "Reference Case 2". As shown in Figure 34, the estimated LGC price is substantially lower in "Reference Case 2".

- **Figure 34 Change in certificate price with changing carbon price, June 2012 dollars**

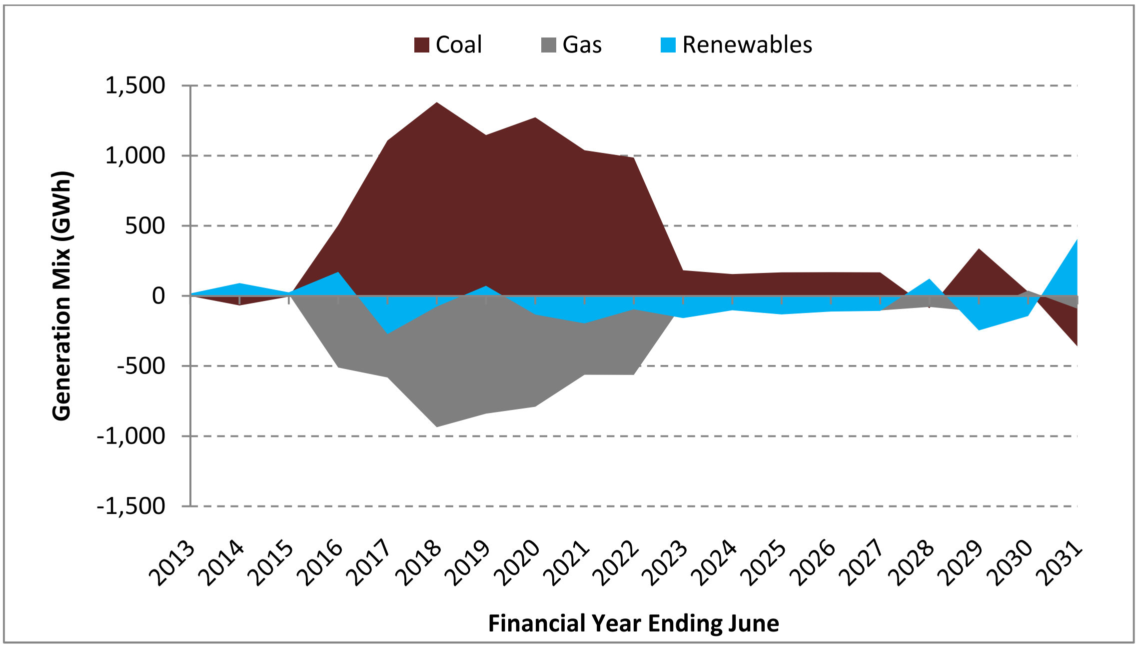


With a lower LGC price there is an average reduction in the certificate cost in "Reference Case 2" of approximately $1.9/MWh per annum from 2013 to 2030.

4.4.3. Changes in thermal energy production

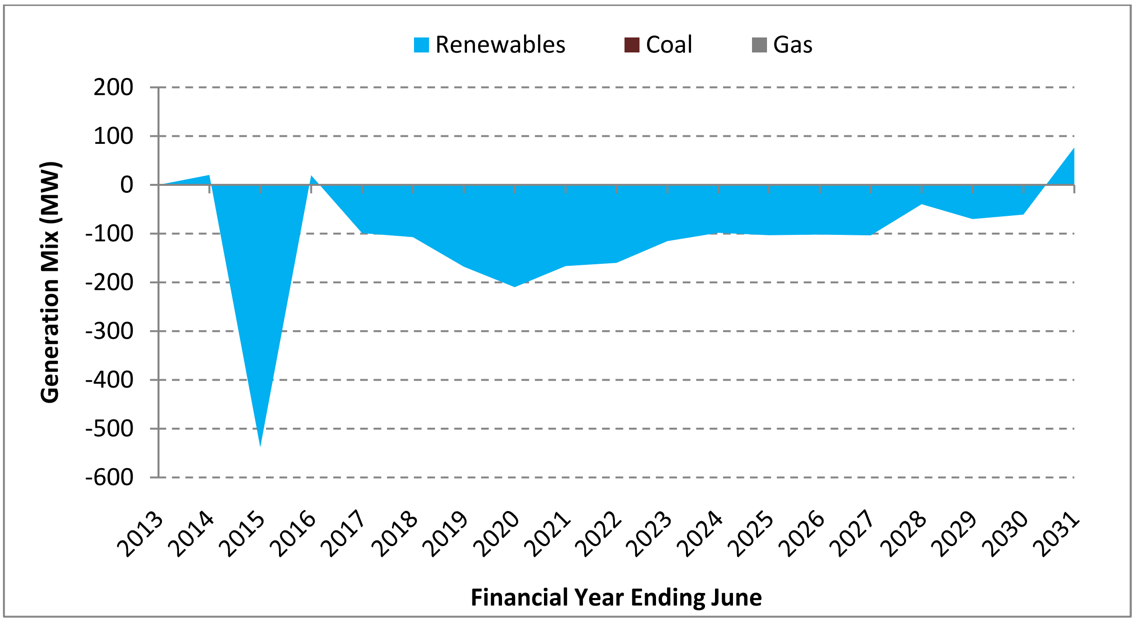
Figure 35 illustrates the difference in energy production from coal, gas and renewable generators under "Reference Case 2". In this case, the higher carbon price in "Reference Case 2" drives more gas generation, slightly more renewable generation in the shorter term and much less coal generation than "Reference Case 1".

- **Figure 35 Difference in generation – ("Reference Case 1" minus "Reference Case 2")**



The variations in carbon price drive changes in the timing of renewable energy development between the two scenarios, with less being developed in "Reference Case 1" in the period prior to 2020, as illustrated in Figure 36. By 2031 there is little difference in the generation mix between the two carbon cases examined since renewable generation becomes economically viable without the need for further policy support, given the assumptions on carbon price and gas prices used.

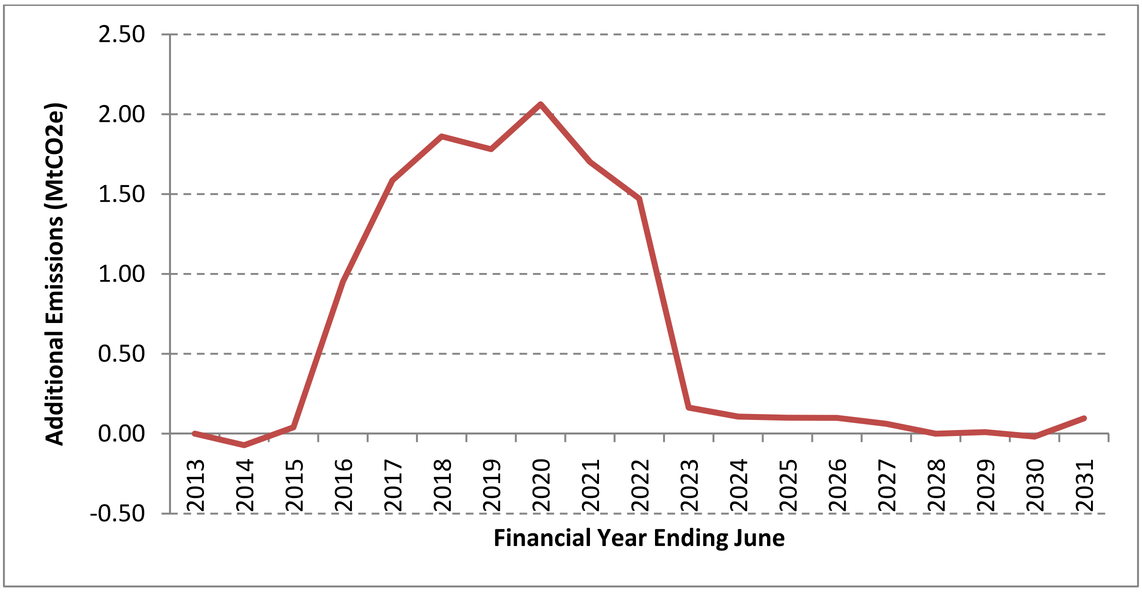
- **Figure 36 Change in capacity ("Reference Case 1" minus "Reference Case 2")**



4.4.4. GHG Emissions reduction

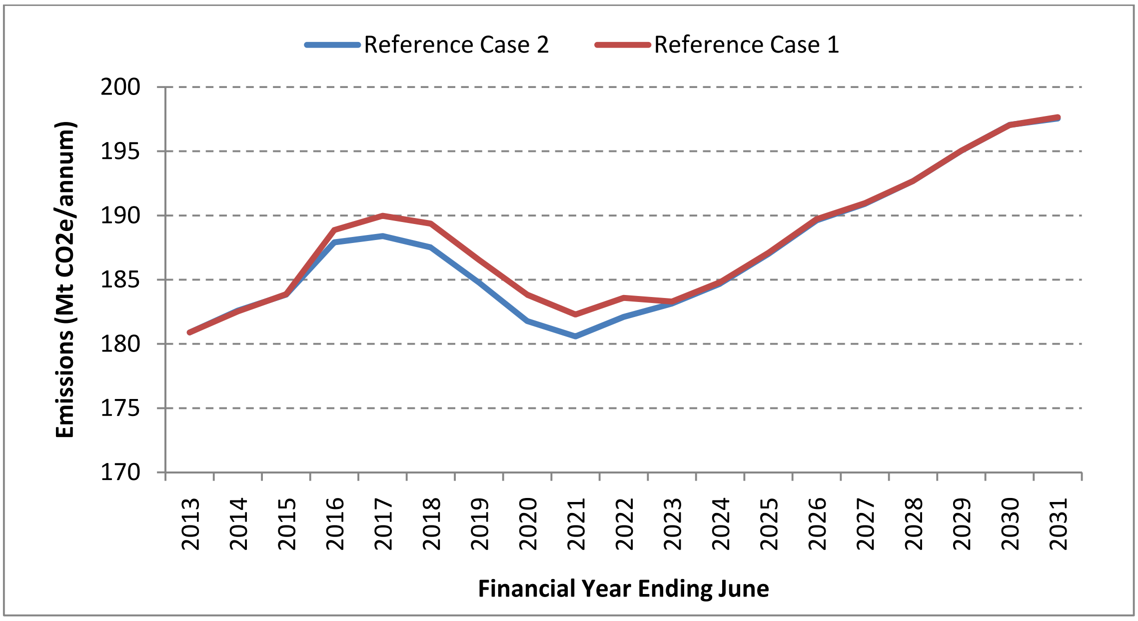
The impact on emissions arising from different carbon prices is shown in Figure 37. Emissions are greater in "Reference Case 1", but the annual differences disappear once the carbon prices between the two reference cases converge.

▪ **Figure 37 Difference in GHG emissions – ("Reference Case 1" minus "Reference Case 2")**



Over the period 2013-2031 the total emissions are 3570 $MtCO_2e$ for "Reference Case 1" and 3558 $MtCO_2e$ for "Reference Case 2", with a potential net reduction of approximately 12 Mt in "Reference Case 2". A comparison of the two emission profiles is shown in Figure 38.

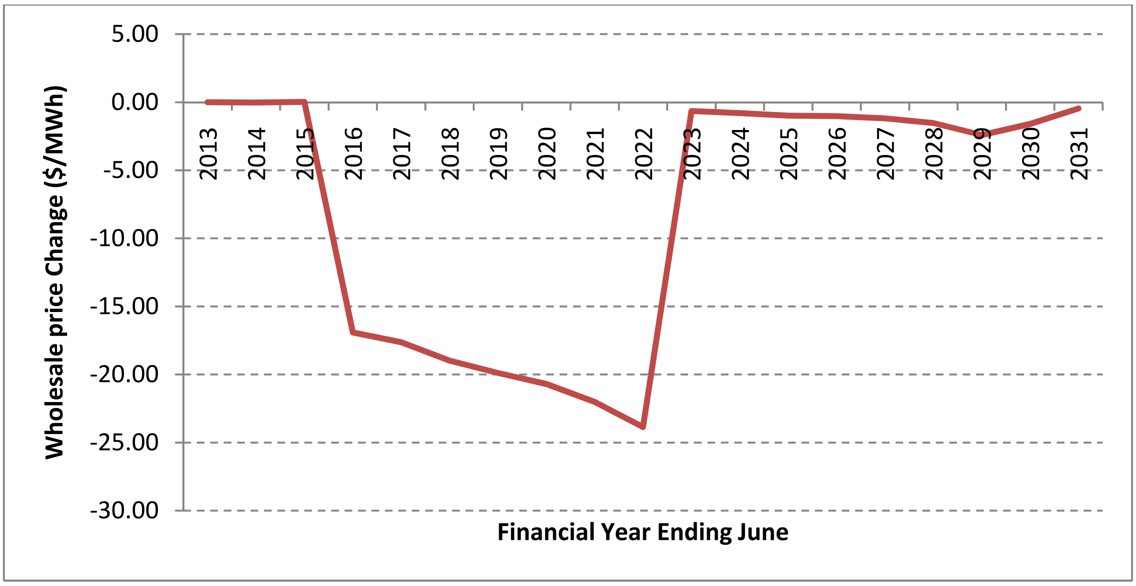
▪ **Figure 38 Comparison of carbon emissions for the two reference cases**



4.4.5. Wholesale price

Wholesale cost changes are driven by differences in carbon price assumed between 2015 and 2023. Wholesale price is lower for "Reference Case 1" illustrated by the step down in 2016 and step back up to converge again from 2023 when carbon prices assumptions realign.

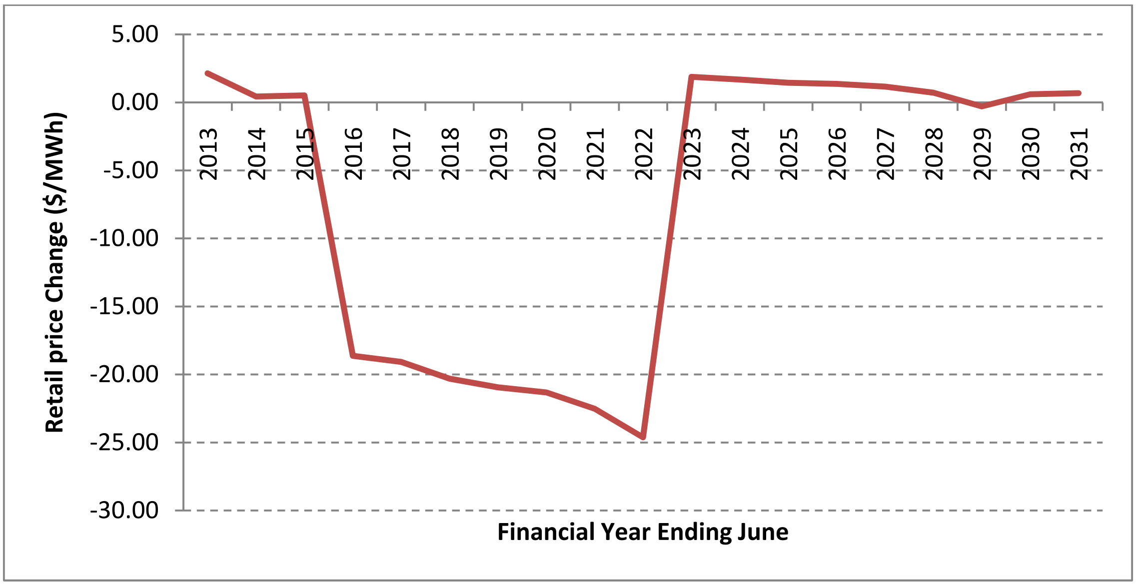
- **Figure 39 Wholesale price change ("Reference Case 1" minus "Reference Case 2"), June 2012 dollars**



4.4.6. Retail price

The carbon price is the main cause of difference in retail price forecast between the two cases. Figure 40 illustrates the estimated impact on the residential retail prices across Australia (i.e. volume weighted retail price across all regions). Typically, due to the addition of retail margin percentages and costs, the absolute change in retail price calculated is normally greater than the change in wholesale price. In Figure 40, this is not evident, since the lower RET certificate cost slightly reduces the impact that the high carbon price has on wholesale prices. The positive change from 2023 onwards reflects the lower ongoing RET certificate cost in "Reference Case 2" and indicates that the retail prices in "Reference Case 1" are expected to be slightly higher from 2023 onwards.

- **Figure 40 Difference in retail price ("Reference Case 1" minus "Reference Case 2")**



The average household bill is expected to be around $50/annum lower over the 2013-2031 period with “Reference Case 1” compared with “Reference Case 2”. This additional cost is equivalent on a NPV basis to around $595 over the period of the study.

4.4.7. Summary of Impact

“Reference Case 2” assumes a higher carbon price and the major impact of this difference is the increase in wholesale and retail prices. Increased wholesale and retail prices result in a change of mix of generation dispatched, with more gas and renewable being utilised than coal generation with a higher carbon price. Accordingly, there is a corresponding reduction in emissions for “Reference Case 2”.

In “Reference Case 2”, the expected RET certificate cost is reduced on average by $1.9/MWh/year due to a lower LGC price. The resource cost increases in “Reference Case 2”, as more expensive gas generation and renewable generation are used in place of coal generation. After 2023, when the carbon prices converge, there is little differential in generation, although the on-going lower RET certificate cost continues until 2031 resulting in a marginally lower retail price from 2023-2031 with “Reference Case 2”.

4.5. Zero Carbon Price

The “Zero Carbon Price” is based on “Reference Case 1” with the only difference being a zero carbon price from 2015 onwards. This analysis uses the CP0 carbon price scenario outlined in Section 3.3.

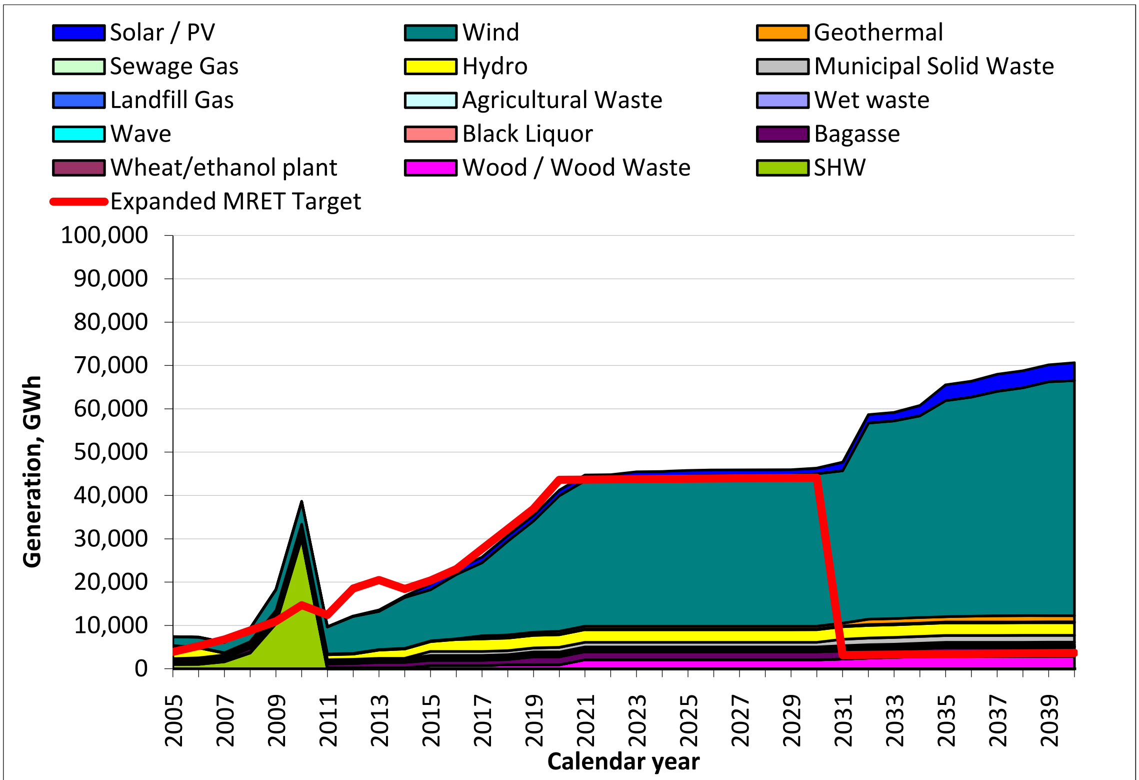
There are no other changes in the “Zero Carbon Price” case. The medium demand scenario (EF2) is used for both “Zero Carbon Price” and “Reference Case 1”.

4.5.1. Energy resources

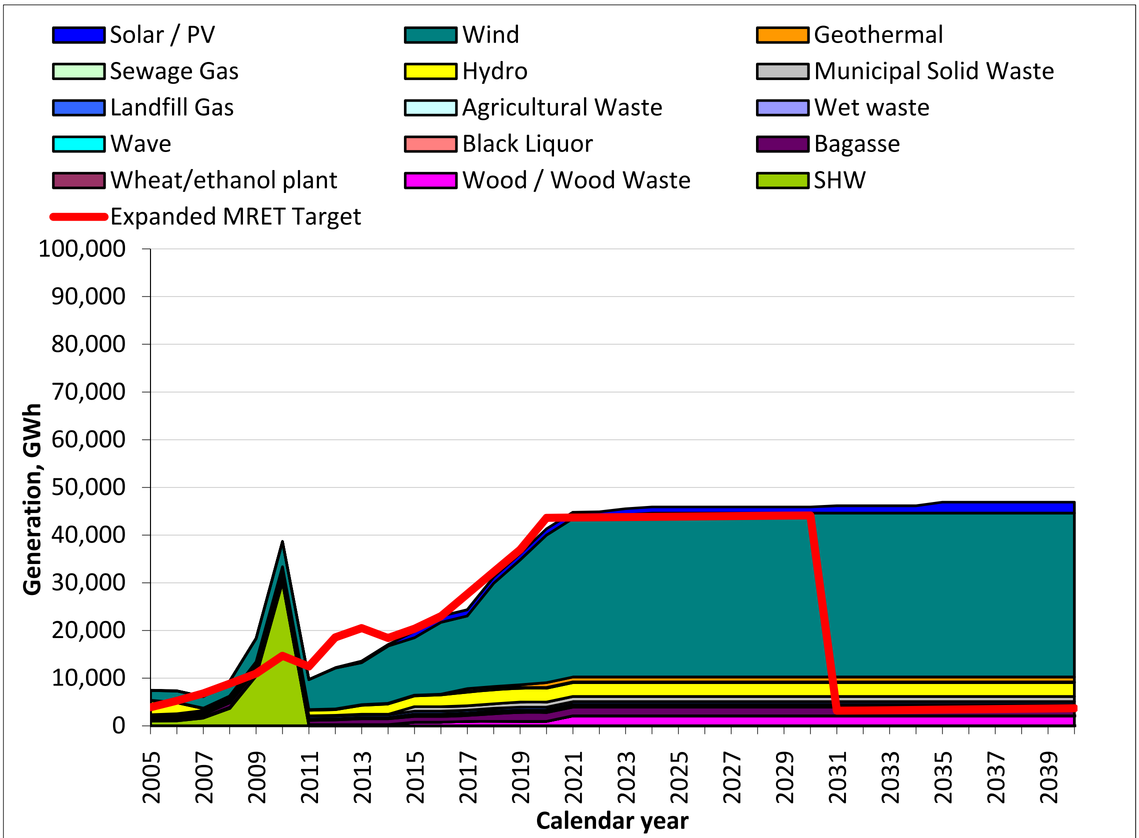
The modelled contribution of renewable energy resources for “Reference Case 1” and “Zero Carbon Price” is shown in Figure 41. Following the completion of the RET scheme in 2020 there is little further renewable development in the “Zero Carbon Price” case during the period considered.

▪ **Figure 41 Resources (“Reference Case 1” and “Zero Carbon Price”)**

RET target resource mix – “Reference Case 1”



RET target resource mix – “Zero Carbon Price”



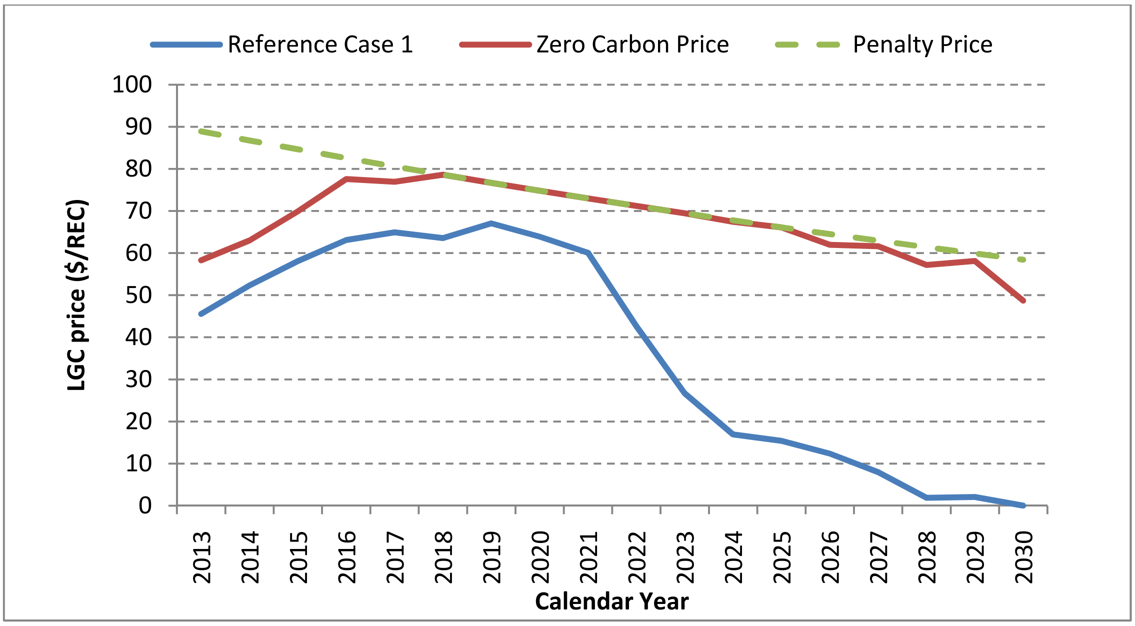
With no carbon price but with demand elasticity included, the lower wholesale prices increase demand by approximately 5,000 GWh by 2020. This change in demand means that in the "Zero Carbon Price" case, the resource cost is expected to increase when carbon price is removed. The resulting change is an NPV of an additional $2.0 billion of resource cost for "Zero Carbon Price".

Based on an estimated increase in emissions of 137 Mt this would equate to a $15/t cost of emissions associated with the "Zero Carbon Price" scenario.

4.5.2. LGC Price

Since the demand for renewable generation is the same in both scenarios, changes in LGC price are driven by lower wholesale prices in the "Zero Carbon Price" scenario. As shown in Figure 42, the LGC price is substantially higher with "Zero Carbon Price" and in fact hits the tax effective penalty price in 2018.

- **Figure 42 Change in certificate price with changing carbon price**



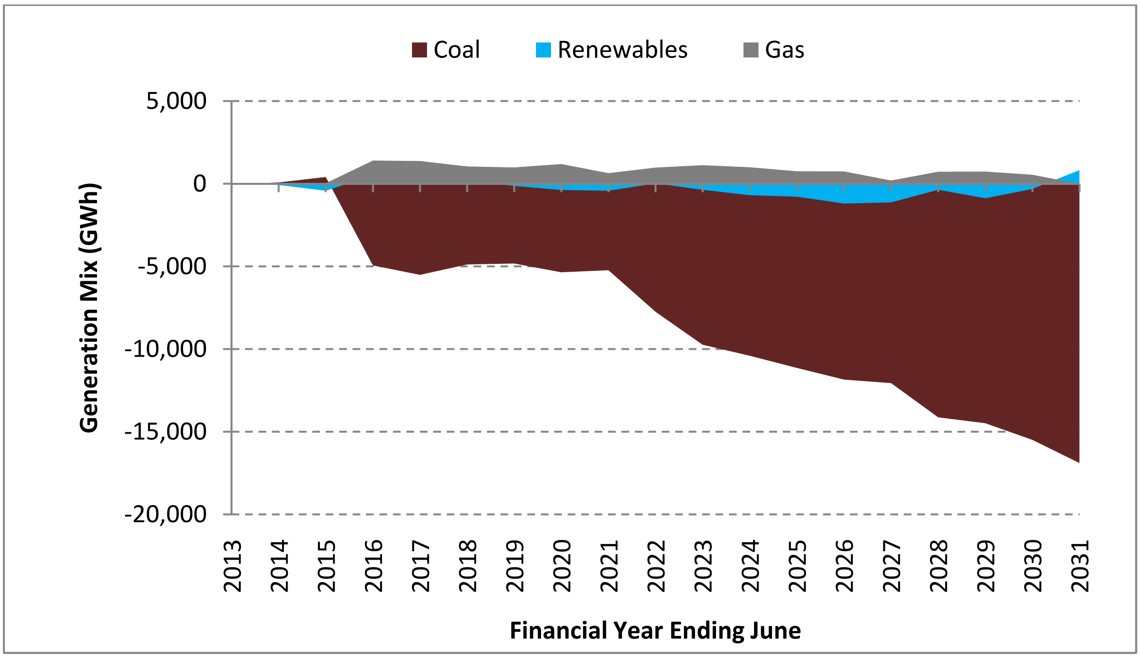
If there was no penalty price, the LGC price would need to be approximately $78/LGC, or approximately $3/LGC higher than the penalty. The target is unlikely to be met in the "Zero Carbon Price" scenario with a shortfall in the order of 3,500 GWh. This shortfall is subsequently built in the period post 2020.

The certificate cost is $14.9/MWh by 2020, approximately $2.1/MWh higher than modelled in "Reference Case 1".

4.5.3. Changes in thermal energy production

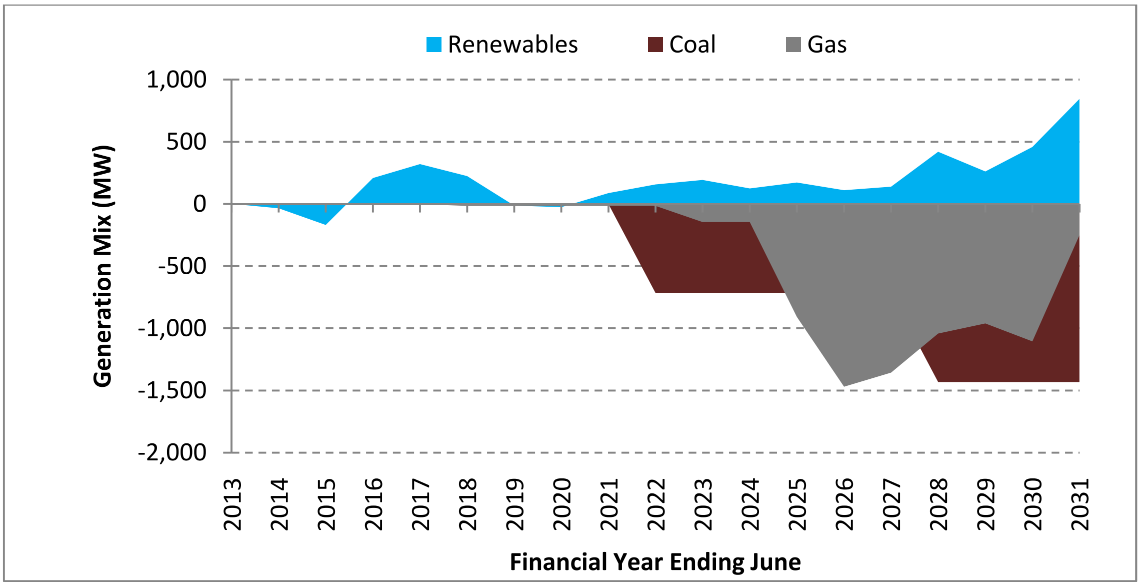
Figure 43 illustrates the difference in energy production from coal, gas and renewable generators between the two scenarios. "Reference Case 1" has more gas and renewable generation and significantly less coal generation than the "Zero Carbon Price" case. The reduction in coal-fired generation in "Reference Case 1" is due to the carbon price, and the price elasticity of demand impacts of this carbon price. In the "Zero Carbon Price", demand is higher and there is little incentive to shift away from coal-fired generation. The "Zero Carbon Price" scenario shows an increased level of black coal generation of approximately 9,200 GWh by 2025, and an increase in brown coal generation of approximately 1,950 GWh.

▪ **Figure 43 Difference in generation – (“Reference Case 1” minus “Zero Carbon Price”)**



The variations in carbon price drive only a marginal change in the initial timing of renewable generation as the RET predominantly determines this development pre 2020. Post 2020, “Reference Case 1” drives more investment in renewable generation, as illustrated in Figure 44.

▪ **Figure 44 Change in capacity (“Reference Case 1” minus “Zero Carbon Price”)**



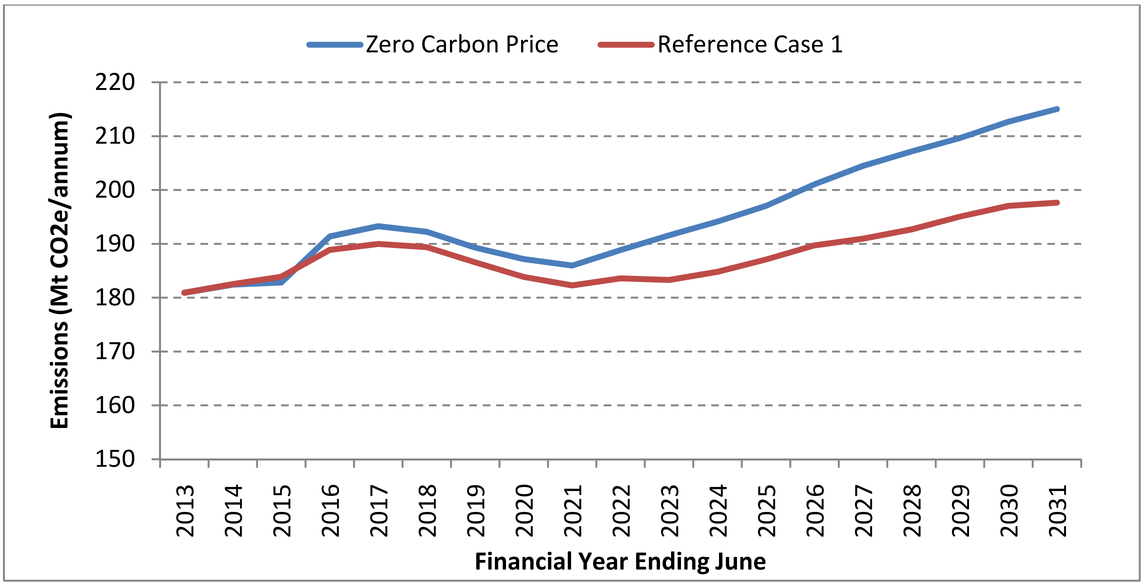
With “Zero Carbon Price” there is a stronger drive to develop lower cost thermal generation, especially coal fired generation. By 2020 new coal plant is commissioned, since the increasing gas price reduces the viability of CCGTs in the absence of a carbon price. It is also assumed in the “Zero Carbon Price” scenario that there is no consideration being given to GHG emission abatement targets in the future, removing some uncertainty and perceived risks surrounding future investment in coal-fired power stations.

4.5.4. GHG Emissions reduction

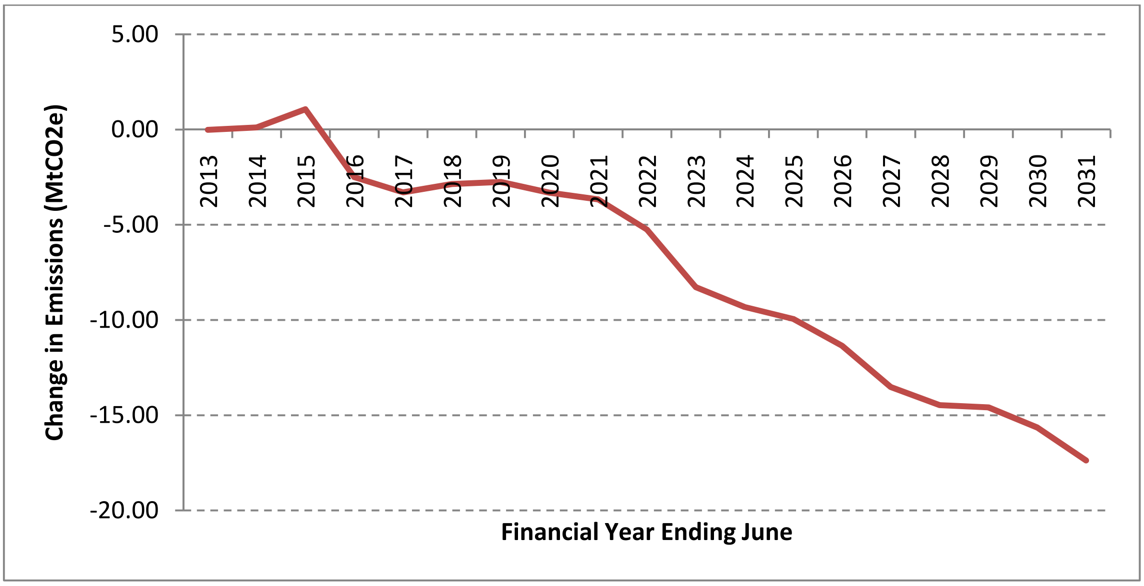
The impact on emissions with and without a carbon price is shown in Figure 45 and the difference in emissions is shown in Figure 46. Without a carbon price, the price-driven increase in consumption and greater development of coal and gas, leads to a continued increase in GHG emissions system-wide.

Over the period 2013-2031 the total emissions are 3,570 $MtCO_2e$ for “Reference Case 1” and 3,707 $MtCO_2e$ for the “Zero Carbon Price” case, therefore the “Zero Carbon Price” results in a potential net increase in emissions of approximately 137 Mt compared with “Reference Case 1”.

- **Figure 45 Comparison of carbon emissions for “Reference Case 1” and “Zero Carbon Price”**



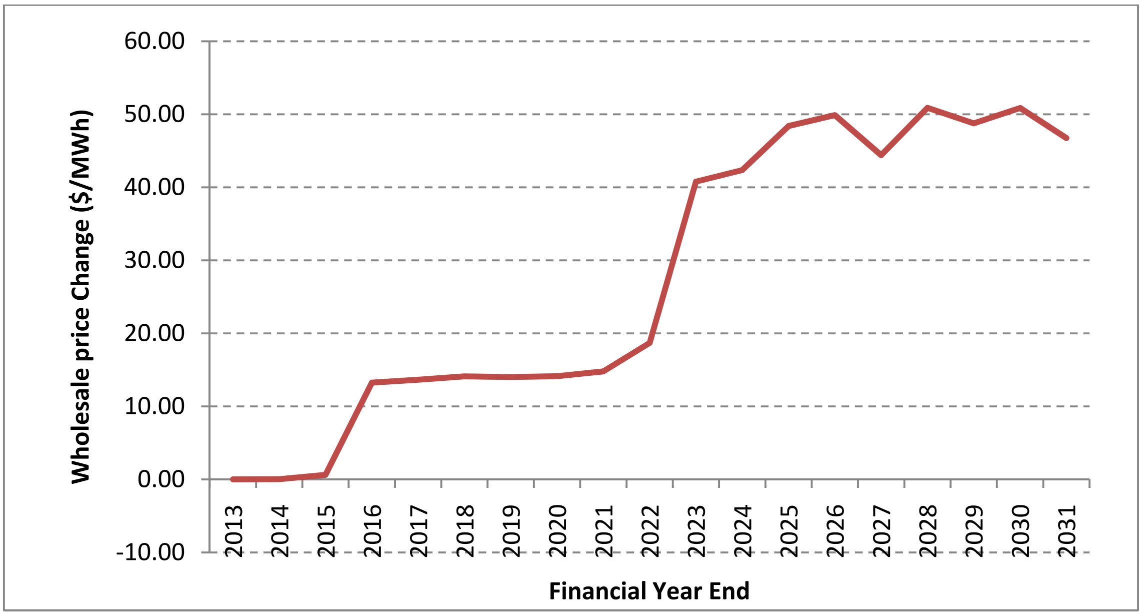
- **Figure 46 Difference in GHG emissions (Reference Case 1 – “Zero Carbon Price”)**



4.5.5. Wholesale price

For the “Zero Carbon Price” case the impact on wholesale price is the greatest of all cases considered. Figure 47 shows the initial price increase in 2016 in “Reference Case 1”, relative to the “Zero Carbon Price” case. Once the three years of legislated fixed carbon prices have passed, there is a price differential of approximately $14.0/MWh for a period of six years. In 2023, when carbon prices increase in “Reference Case 1”, the price differential increases noticeably to more than $40/MWh.

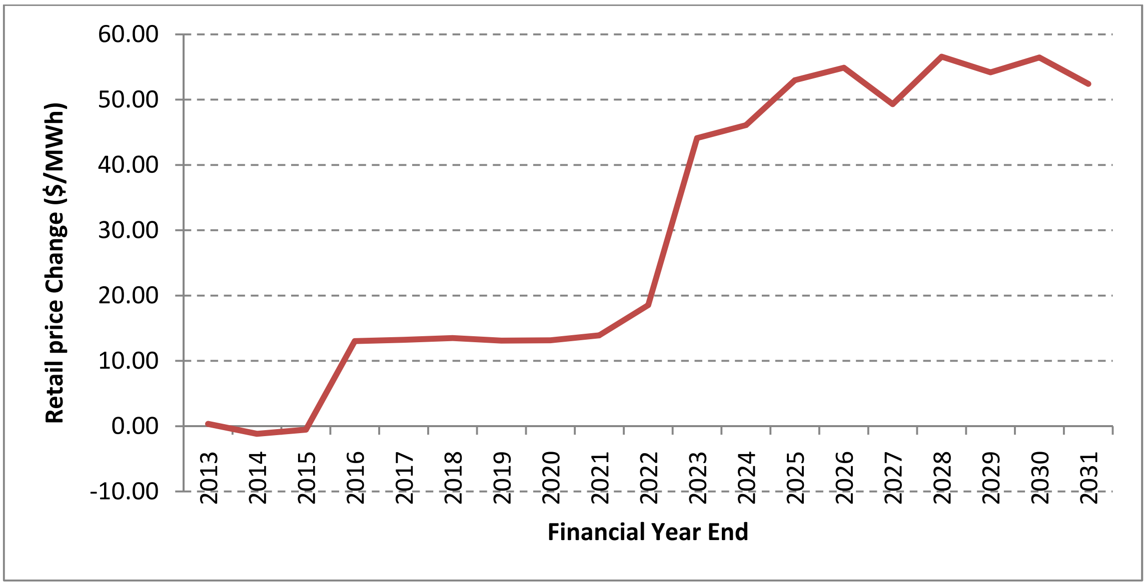
- **Figure 47 Wholesale price change (“Reference Case 1” minus “Zero Carbon Price”)**



4.5.6. Retail price

The impact of the wholesale price flows through to the residential retail price and is typically exaggerated slightly due to the retail price margin assumed. This is illustrated in Figure 48 where the same price trend is shown as for the wholesale price, albeit of slightly greater magnitude. Offsetting the price differential to some extent is the lower certificate cost associated with “Reference Case 1”.

- **Figure 48 Retail price increase with "Reference Case 1" compared to "Zero Carbon Price"**



The average household bill is expected to be higher in "Reference Case 1" in comparison to a "Zero Carbon Price" case in the order of $208/annum over the 2013-2031 period. The NPV of the difference between the cases is an additional $1,611 per household.

4.5.7. Summary of Impact

With the "Zero Carbon Price" scenario, wholesale and retail prices are expected to be substantially lower over the entire period compared with "Reference Case 1". The average household bill is likely to be lower under the "Zero Carbon Price" case.

The LGC price is expected to hit the tax effective penalty price under the "Zero Carbon Price" case. This indicates the existing RET is unlikely to be met under this case with a shortfall in the order of 3,500 GWh. The analysis shows the LGC price would need to be approximately $78/LGC, or $3/LGC higher than the tax effective penalty price for the target to be met. The "Zero Carbon Price" forecasts that the shortfall in renewable generation would subsequently be built during the period post 2020.

There is a substantial change in generation mix, particularly post 2020 when new entry is required. More coal-fired generation is observed in the "Zero Carbon Price" case. Post 2020, after the RET is complete, further development of renewable generation is negligible in the "Zero Carbon Price". This results in greater emissions in the order 137 $MtCO_2e$ over the planning period. Coupled with a $2.0 billion (NPV) increase in resource cost, this equates to a GHG emissions cost of approximately $15/t.

4.6. “Low Demand” Case

In the “Low Demand” case, “Reference Case 1” was altered to include a low demand projection in order to explore the change in renewable development and the impact this has on the RET. The lower demand (EF1) has been applied and this is illustrated in Section 3.4.

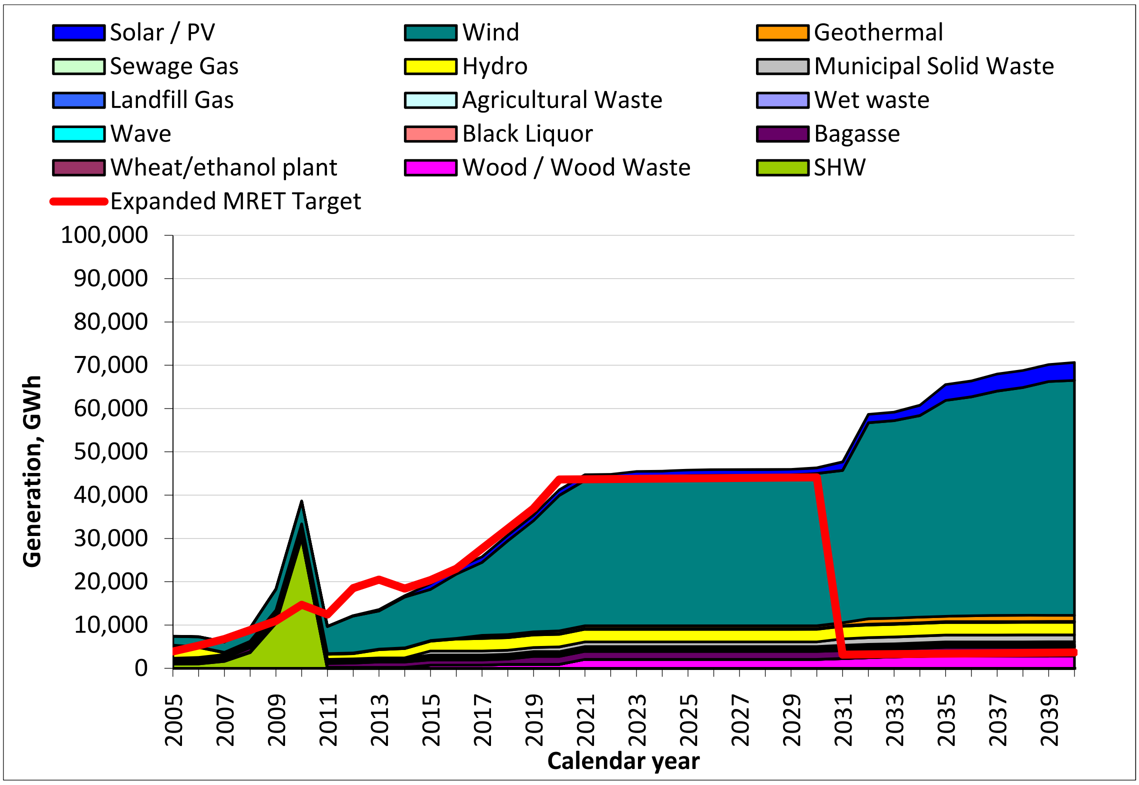
For the “Low Demand” case, the existing RET target (LS2) and the low carbon price (CP1) were used.

4.6.1. Energy resources

The modelled contribution of renewable energy resources for the “Low Demand” case compared with ”Reference Case 1” is shown in Figure 49.

- **Figure 49 Resources ("Reference Case 1" and "Low Demand")**

RET target resource mix – "Reference Case 1"



RET target resource mix – "Low Demand"

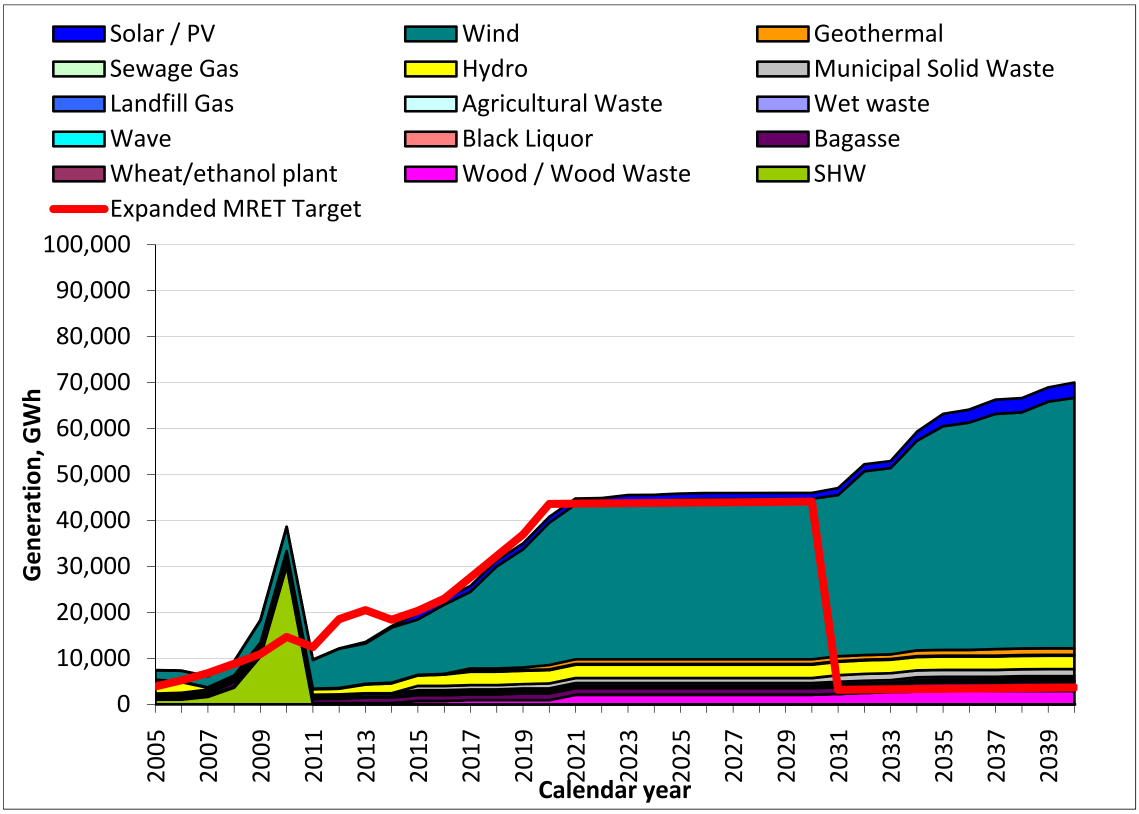


Figure 49 shows a minor delay in the expected development of further renewable generation post 2030 in the "Low Demand" case (EF1). Pre 2030, the RET target drives the renewable development in both cases.

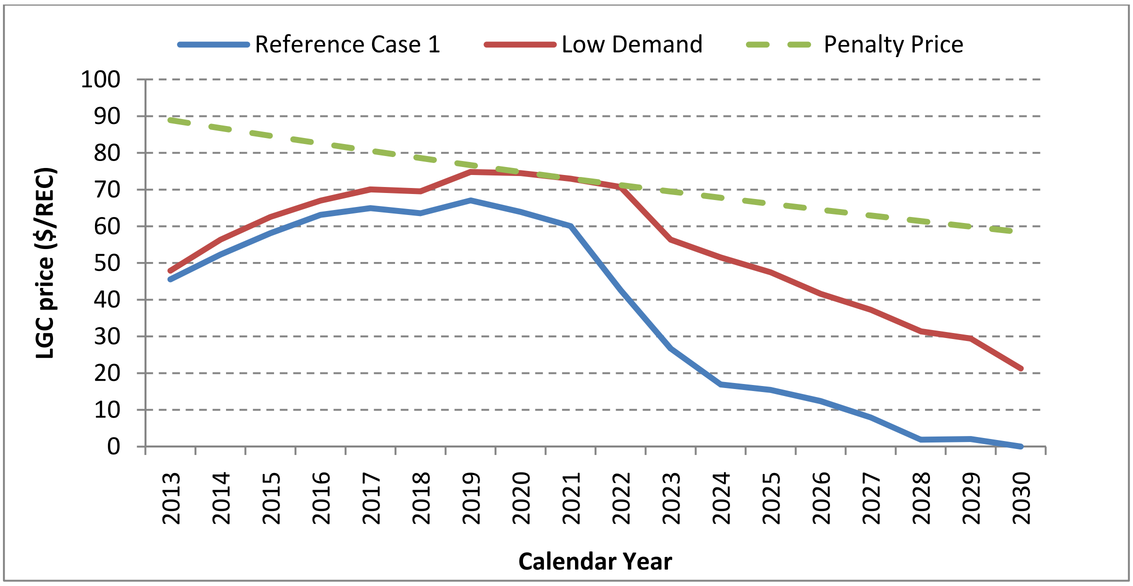
With the "Low Demand" case, the expected resource cost is considerably lower with an NPV reduction of $5.9 billion over the 2013-2031 period.

Based on an estimated decrease in emissions of 349 Mt this equates to a potential $17/t benefit of reduced GHG emissions associated with the "Low Demand" case.

4.6.2. LGC Price

The demand for renewable generation is the same in both scenarios, increases in LGC price are driven by lower wholesale prices in the "Low Demand" case. Figure 50 indicates that the penalty price is reached in the "Low Demand" case in 2021 and is close to being reached in 2020 and 2022.

- **Figure 50 Difference in certificate price ("Reference Case 1" compared with "Low Demand" and penalty Price**

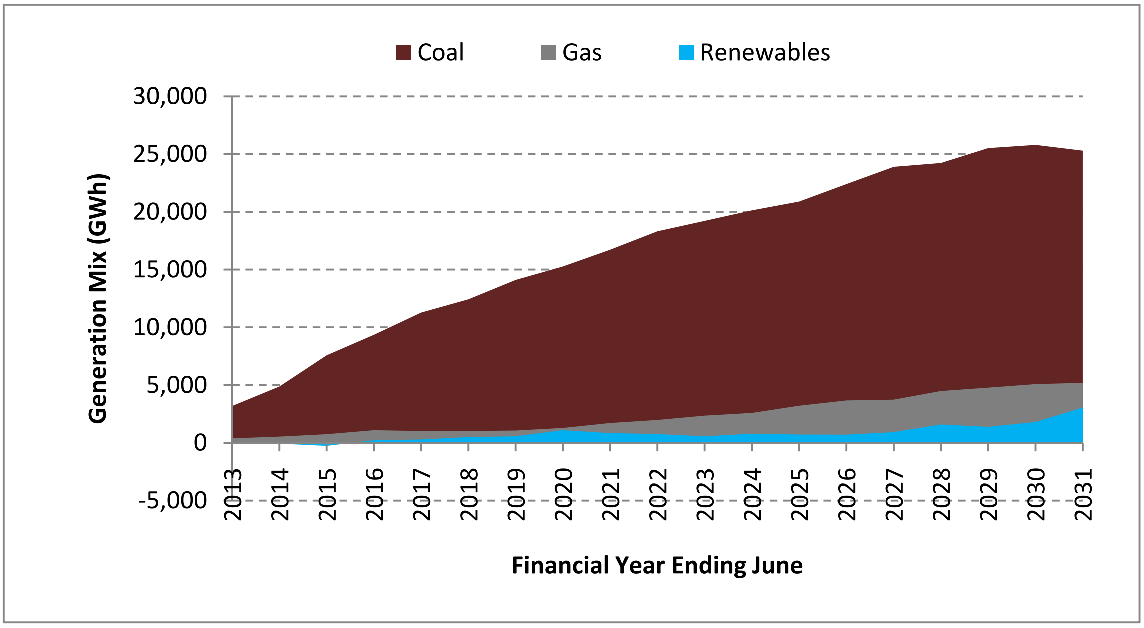


The certificate cost for the "Low Demand" case in 2020 is estimated to be $15.0/MWh, approximately $2.2/MWh higher than "Reference Case 1" with medium demand. This increase is due to the higher LGC cost and the lower demand across which the cost is spread.

4.6.3. Changes in thermal energy production

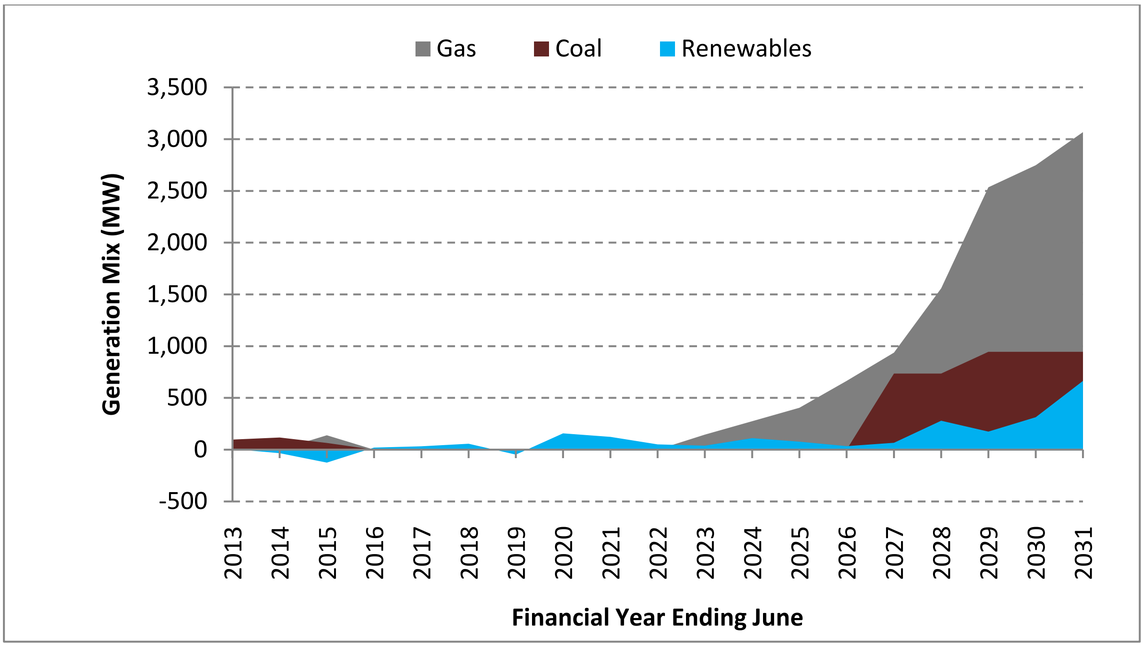
Figure 51 illustrates the difference in energy production from coal, gas and renewable generators between "Reference Case 1" and "Low Demand". The medium demand results in more generation from all technologies, particularly coal-fired generation. Under a "Low Demand" scenario the greatest impact is likely to be on coal generation over the entire period with some impact on renewable generation and gas-fired generation post 2020.

▪ **Figure 51 Difference in generation ("Reference Case 1" minus lower demand case)**



"Reference Case 1" forecasts significantly more new investment (increased capacity) post 2020, although only a marginal change pre 2020, as can be seen in Figure 52. The requirement for additional thermal generation capacity under the "Reference Case 1" (i.e. medium demand) is low pre 2020 and hence the difference in the level of investment is expected to be minor between the two cases in this period. In the "Low Demand" case, the need for new generation capacity is further delayed post 2020, resulting in less new gas-fired generation peaking capacity and renewable generation investment. In addition, low demand growth advances retirement of some coal-fired generation capacity.

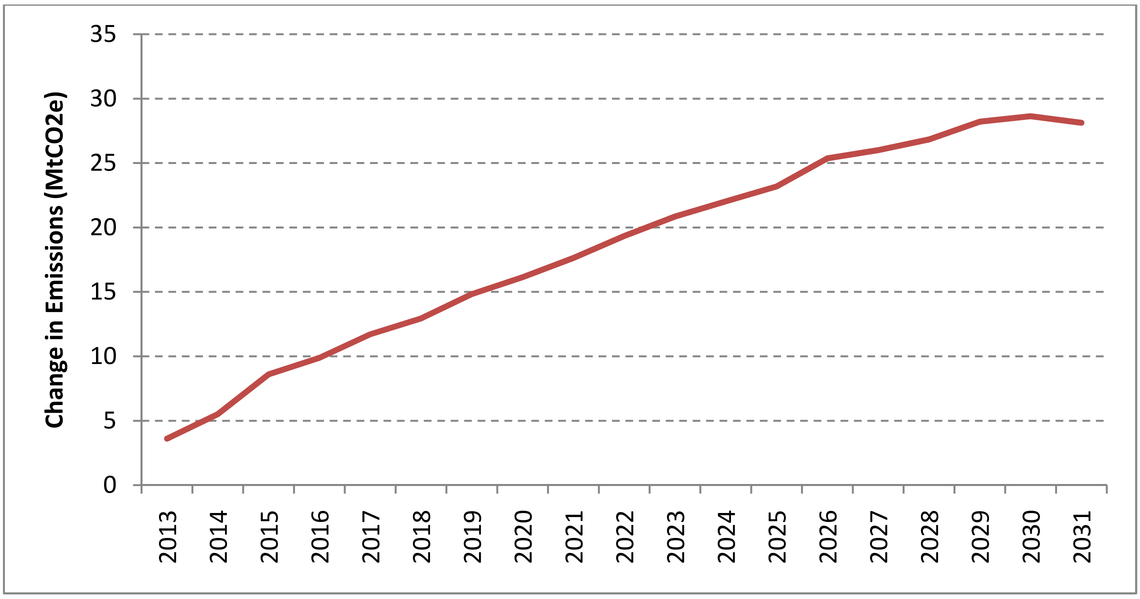
▪ **Figure 52 Change in capacity ("Reference Case 1" – "Low Demand")**



4.6.4. Emissions reduction

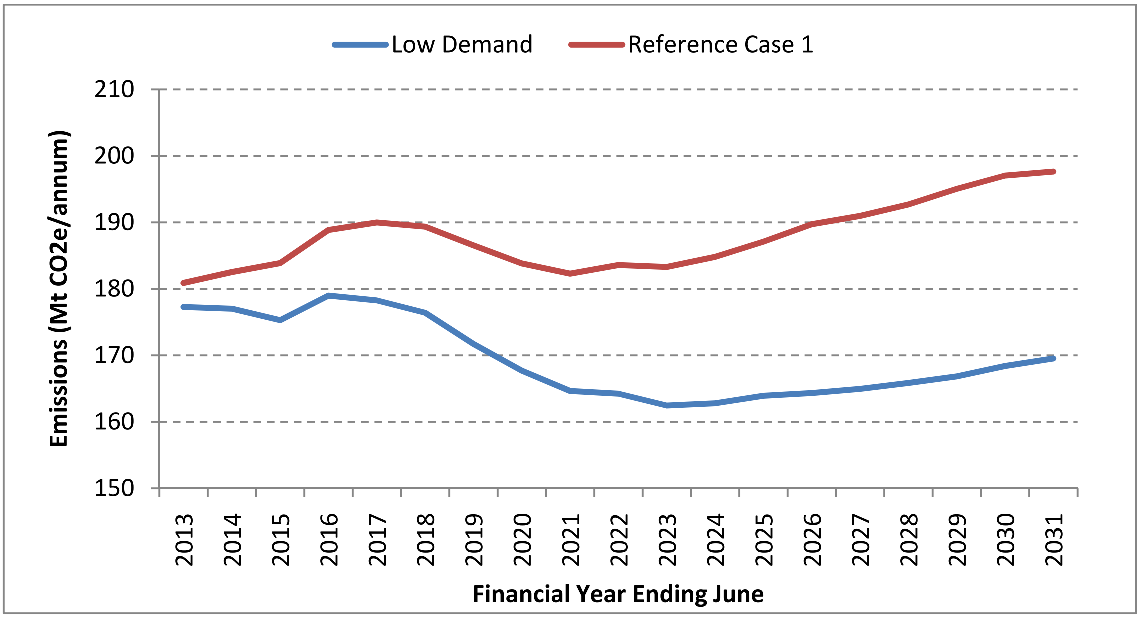
The difference in emission production between “Reference Case 1” and “Low Demand” scenarios is shown in the Figure 53. More GHG emissions are produced by “Reference Case 1”, and the difference in emission levels continues to increase between the two scenarios over time.

- **Figure 53 Change in emissions (“Reference Case 1” – “Low Demand”)**



Over the period 2013-2031 the total emissions are 3,570 $MtCO_2e$ “Reference Case 1” while they are substantially lower, 3221 $MtCO_2e$, for the “Low Demand” case. This results in a potential net reduction of approximately 349 Mt over the analysis period. A comparison of the two emission profiles is shown in Figure 54.

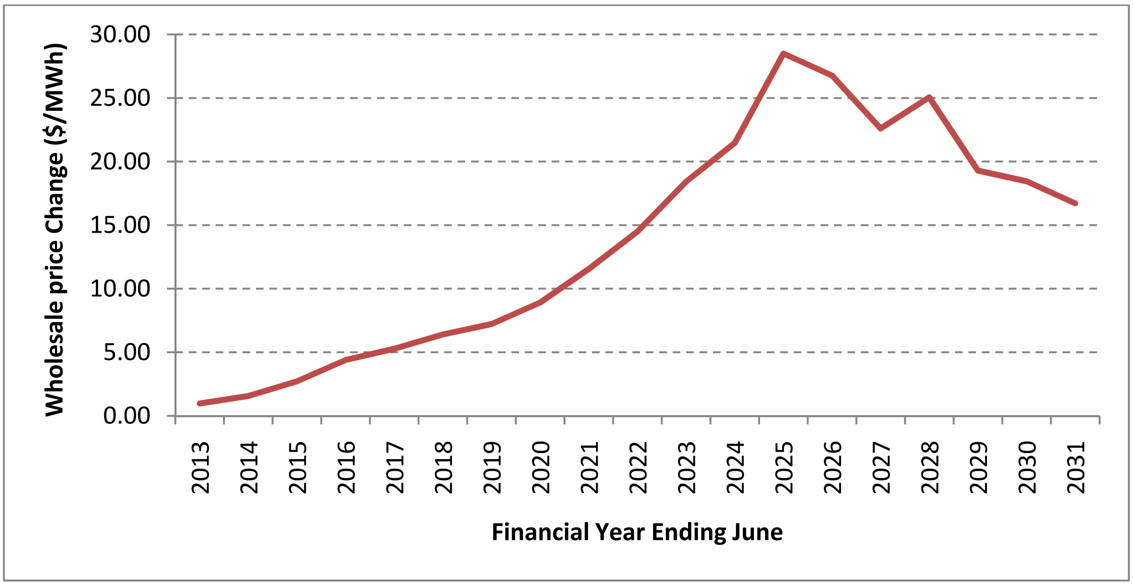
- **Figure 54 Comparison of carbon emissions for “Reference Case 1” and “Low Demand”**



4.6.5. Wholesale price

Due to the lower demand it takes longer for supply and demand to become balanced, and therefore the wholesale price is lower than "Reference Case 1" for a longer period of time. This is shown in Figure 55. The decline in the wholesale price difference post 2025 is due to the addition of new capacity in "Reference Case 1". As the price reaches new entrant levels, wholesale prices start to level off.

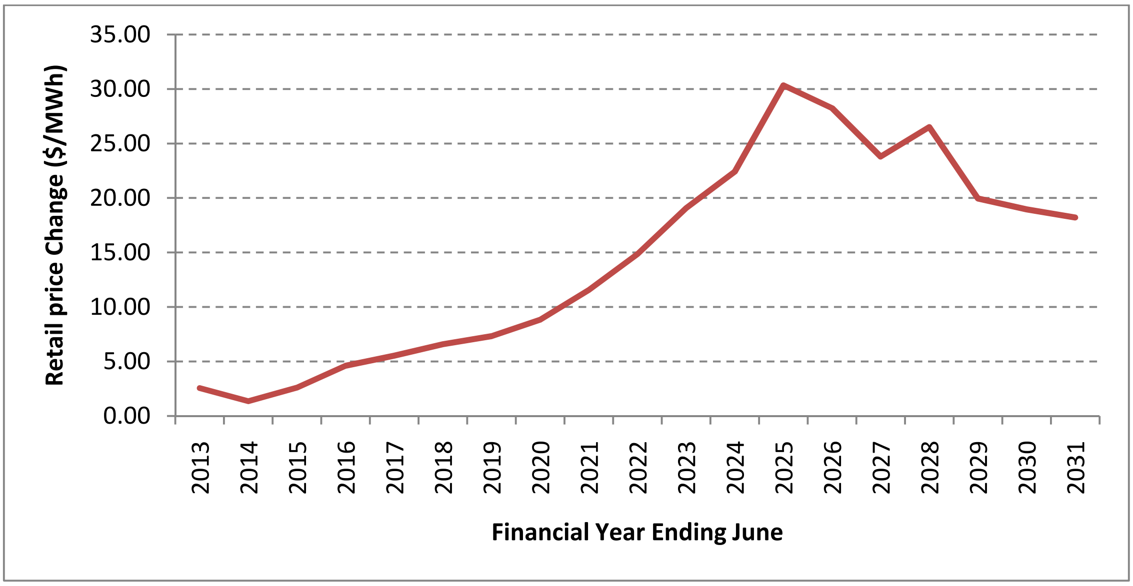
- **Figure 55 Wholesale price increase with "Reference Case 1" minus "Low Demand".**



4.6.6. Retail price

The wholesale price trends described above follow through to the differences in retail prices. The retail prices (shown in Figure 56) result in a net reduction in household bills of $101 per annum relative to "Reference Case 1"over the 2013-2031 period or an NPV of $827 per household.

- **Figure 56 Retail price increase ("Reference Case 1" minus "Low Demand")**



4.6.7. Summary of Impact

In the “Low Demand” scenario there is an expected reduction in the resource cost ($5.9 billion) as well as GHG emissions (349 Mt) equivalent to a GHG emission abatement cost of $17/t. These changes are driven by the lower need for coal, gas and renewable generation. Of these, the coal generation levels are most impacted.

The wholesale and retail prices are lower although the difference decreases towards 2030. This decrease is driven by the prices in “Reference Case 1” reaching new entrant levels subduing further price increases and effectively narrowing the price gap between the cases. No price elasticity of demand impacts have been factored into these lower demand forecasts, so this assessment may be an upper bound on the true impact of lower demand.

5. Reliability and Network modelling

To complement the above analysis a detailed analysis was undertaken on select cases and years to test whether there were any reliability or network issues related to the degree of renewable development.

A detailed Monte Carlo simulation model (PLEXOS) was utilised to model the system in detail. PLEXOS models the system on an hourly basis modelling all transmission links, system normal network constraints, generators and demand sources. This allows various generator, demand and transmission network solutions to be tested and analysed to identify any future problems.

The scenarios and years tested were:

- "Reference Case 1" for the years 2015 and 2020
- "No RET" case for 2015 and 2020
- "Reference Case 2" for the years 2015 to 2020.

The years 2015 and 2020 were selected for these cases as 2015 is reflective of modelling the current network and system prior to any need for upgrades and prior to the existing RET target starting to increase dramatically. While 2020 is the year when the existing RET reaches the 41,000 GWh target and in effect it should see the system at its maximum stress in terms of renewable development.

The STRATEGIST analysis was utilised in the PLEXOS modelling to inform upgrades (network and generation), retirements and the renewable generation developments. The VIC-SA network upgrade recommended in the Heywood RIT-T undertaken by AEMO and ElectraNet was assumed to proceed in 2016/17 in all scenarios. No other major transmission augmentations were selected from the STRATEGIST modelling within the planning horizon. Retirements of black and brown coal-fired generation were also determined from the STRATEGIST modelling based on an assessment of the financial viability of the plant, although retirements were generally delayed until after 2023 due to the low carbon price assumptions and high gas prices assumed. The recent announcements regarding mothballing of Tarong and Yallourn units were not included as these announcements came after the modelling had commenced.

One hundred Monte Carlo simulations were run for each year and case to ensure that there were no adverse impacts of the renewable generation development on either network congestion or unserved energy that would render the solutions infeasible.

The results indicated that the available renewable energy could be dispatched under all three cases in both 2015 and 2020. There was no renewable generation constrained off due to network constraints. Moreover, due to the surplus supply situation projected, unserved energy did not exceed the 0.002% reliability criteria in any cases or years[10]. In most cases, there was no energy unserved.

The modelling was conducted on an hourly time step and, as such, did not consider ramp rate constraints which may become more restrictive with large volumes of intermittent generation in the system. While

10 The expansion plan determined by the Strategist model ensured that there was sufficient reserve capacity in the system to meet the reliability criteria, with additional peaking generation being commissioned if needed for reliability. However, this expansion plan was not informed with respect to the impact of network constraints that could further constrain generation and lead to unserved energy. Therefore, one of the purposes of the PLEXOS modelling was to verify that the reliability criteria could still be met when detailed transmission constraints were taken into account.

outside the scope of the current study to investigate potential intermittency issues associated with integrating large volumes of wind in the NEM, SKM MMA notes that these issues are being monitored and investigated by a number of organisations, including AEMO[11] and AEMC[12]. Strategic initiatives, such as increasing demand flexibility, are also being explored in response to potential intermittency challenges.

Moreover, while the output from wind and solar generators varies with environmental conditions these changes are seldom completely unpredictable and all occur over reasonable timeframes. A significant weather system will not coincidentally affect all wind farms in a region, indeed it is impossible for a weather system to affect all wind turbines in a farm at the same instant if only by virtue of the time for the weather front to cover the distance between the machines.

Large scale variations in output from renewable generators usually occur over relatively long time frames. AEMO has developed a world class forecasting system to aid in predicting large variations and, if the contribution from renewable energy is sufficiently uncertain to threaten system security, AEMO will implement constraints on generators to mitigate that risk. These would include constraining the intermittent generation to a lower level of output, altering dispatch patterns to bring on additional conventional generating plant or seeking to increase levels of spinning reserve available to a region either locally or via interconnection. It does not necessarily result directly in the requirement for additional fast response open cycle gas generation. Gas turbines can start quickly but they are an expensive option when other generators across an interconnected system can deliver the same outcome.

[11] http://www.aemo.com.au/Electricity/Planning/Reports/South-Australian-Advisory-Functions/Wind-Study-Report

[12] http://www.aemc.gov.au/Media/docs/ROAM%20Report-566727a5-bfb8-4c7d-a88a-0b9469e5d19c-0.pdf

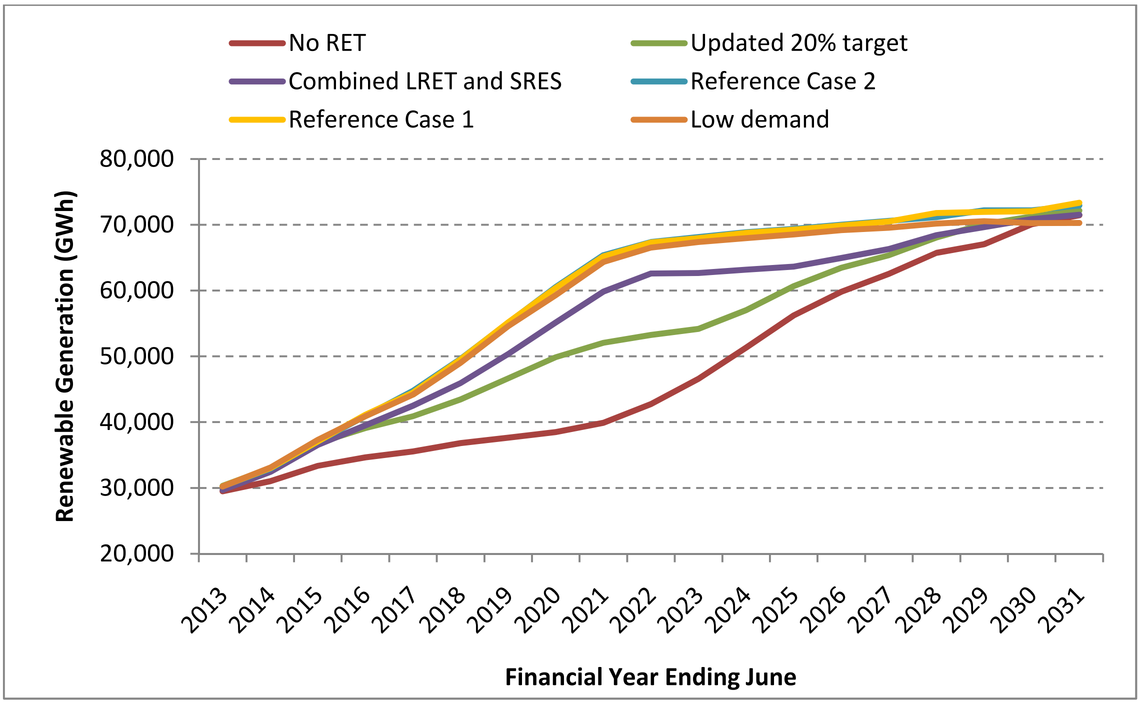
6. Summary and conclusions

The modelling undertaken has explored the potential impact on a number of criteria of changing various parameters including the RET target, demand forecast and carbon prices. The following sections summarise the observations of the impact of different parameters across the range of criteria considered.

6.1.1. Renewable Development

In the cases with a larger renewable energy target or high carbon price, the timing of renewable generation development is advanced. Figure 57 compares the renewable development under all RET variations analysed. The "Reference Case 2" scenario has the highest and earliest renewable generation development during the 2013 - 2031 period, although differences between "Reference Case 1" and "Reference Case 2" are negligible. While there is some growth in small-scale solar PV and SHW, even without a RET, the RET is the main driver of renewable generation development in the period to 2020.

- **Figure 57 Comparison of renewable development**



Post 2020, increases in carbon prices and gas prices improve the economic viability of renewable generation. Consequently, additional investment in renewable generation over and above the RET is observed from 2023 onwards.

Comparing different renewable energy targets with the same carbon price (i.e. CF1), by 2031 there are similar levels of renewable generation development. This highlights that variations to the RET are likely to impact on the timing of new renewable generation development in the next 10 years or so, but not in the longer term. Under the "Updated 20% Target", approximately 14,500 GWh of renewable generation development is delayed by 5 to 6 years. The "Combined LRET & SRES" scenario results in deferral of approximately 5,400 GWh of new renewable development, again for a period of 5 to 6 years.

In the "No RET" case, with the RET removed from 2013 onwards, there is over 24,500 GWh less renewable generation by 2020, compared to the "Reference Case 1" which continues the existing target.

Post 2020, carbon prices and gas prices provide the incentive for additional renewable generation development even without RET.

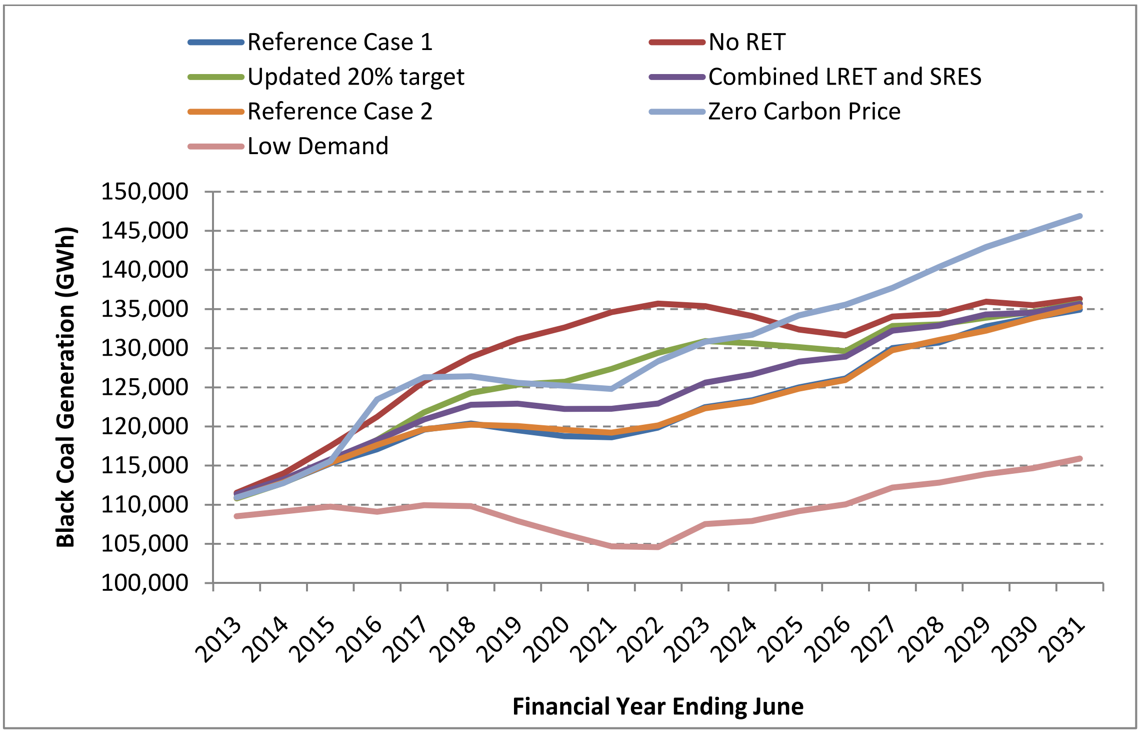
While not shown in Figure 57, the “Zero Carbon Price” case drives lower levels of renewable development post 2020 since the wholesale electricity prices are not high enough to make renewable generation development economically viable without further policy support.

Additional renewable generation added to the current market is likely to displace existing coal-fired generation. The analysis indicates that, in GWh terms, the black coal-fired generators were impacted most, although on a percentage basis the reduction in brown coal-fired generation was slightly greater. Compared to the “No RET” case, “Reference Case 1” resulted in a reduction of approximately 16,000 GWh of black coal generation and 7,900 GWh of brown coal generation by 2021. The changes in black and brown coal generation between cases and from current levels are illustrated in Figure 58 and Figure 59 for black coal and brown coal generation respectively.

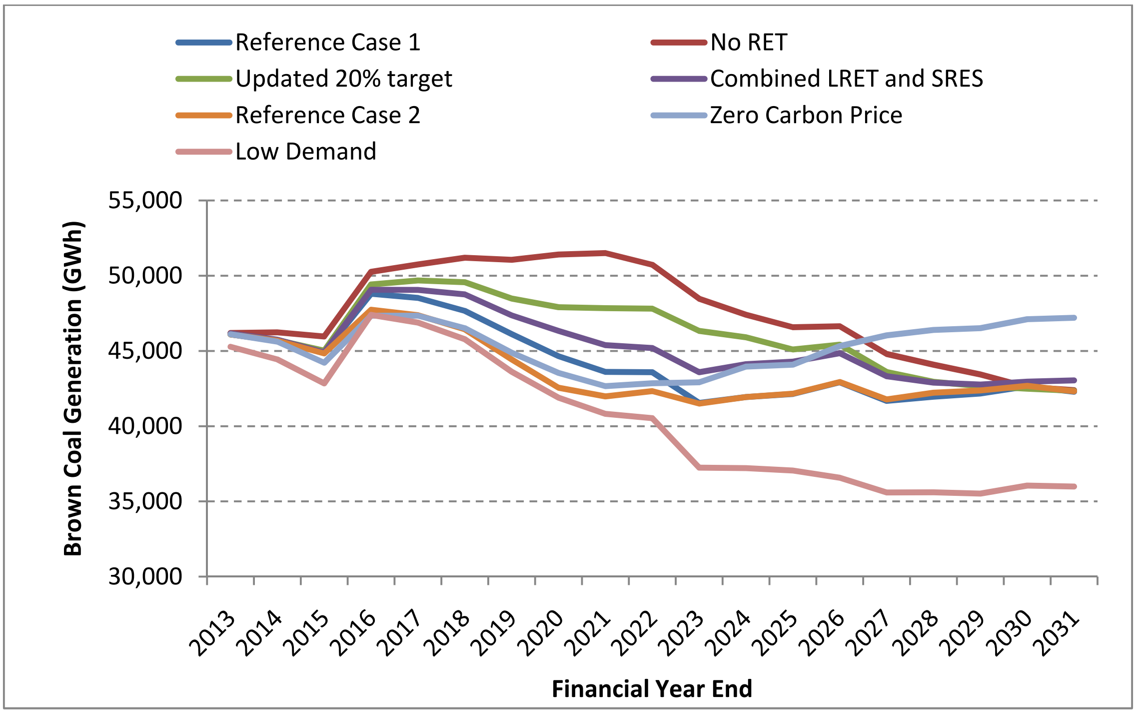
Figure 58 shows that, while the various RET cases lead to reductions in black coal-fired generation, black coal-fired generation is still expected to increase from current levels in response to demand growth in all but the “Low Demand” case. Conversely, after an initial generation increase at the end of the three-year fixed carbon price period, brown coal generation levels generally decline over the longer term as carbon prices increase; the exception being in the ‘Zero Carbon Price” case where brown coal generation continues to be competitive with other thermal generation alternatives.

In the market modelling undertaken, heat rate curves are modelled for the coal-fired generators so that any increases in marginal costs arising from operating plant at lower utilisation levels can be captured. It should also be acknowledged that during the course of this analysis, announcements have been made regarding mothballing of coal units at Tarong and Yallourn. To the extent that these closures will allow the remaining incumbents to operate at higher utilisation levels, the estimated impact of coal-fired generators operating at less efficient levels may be overstated in this analysis.

- **Figure 58 Black Coal Generation by case (GWh)**



- **Figure 59 Brown Coal Generation by case (GWh)**



The only major difference in gas-fired generation between cases occurred in the "Low Demand" and "Zero Carbon Price" cases. In the "Low Demand" case there was less gas generation in the order of 3,000 GWh by 2031 when compared to "Reference Case 1" with a medium demand forecast.

6.1.2. Greenhouse gas emissions

With more renewable development total GHG emissions are reduced across the Australian electricity generation sector. This is due to the displacement of both brown and black coal-fired generation by renewable generation. Table 3 illustrates the relative change from "Reference Case 1", with a positive number illustrating greater emissions for the case shown. Figure 61 further illustrates the relationship between resource cost and GHG emissions under the various RET cases.

- **Table 3 Resource Cost and Emissions Changes compared to "Reference Case 1"***

	NPV change in Resource cost ($M)	Change in Emissions (MT)	Cost of change in Emissions ($/t)^
Updated 20% Target	-4,457	119	-38
No RET	-8,645	217	-40
Combined LRET and SRES	-2,390	68	-35
Reference Case 2	437	-12	-36
Zero Carbon Price	2,035	137	15
Low Demand	-5,938	-349	17

* A negative value means the parameter is lower in the nominated case than in Reference case 1.

^ Cost of emission abatement calculated based on methodology outlined by DCCEE in "Estimating the Cost of Abatement", http://www.climatechange.gov.au/~/media/publications/abatement/20111011-estimating-the-cost-of-abatement-pdf.pdf

- **Figure 60 Reduction in resource cost versus increase in GHG emissions**

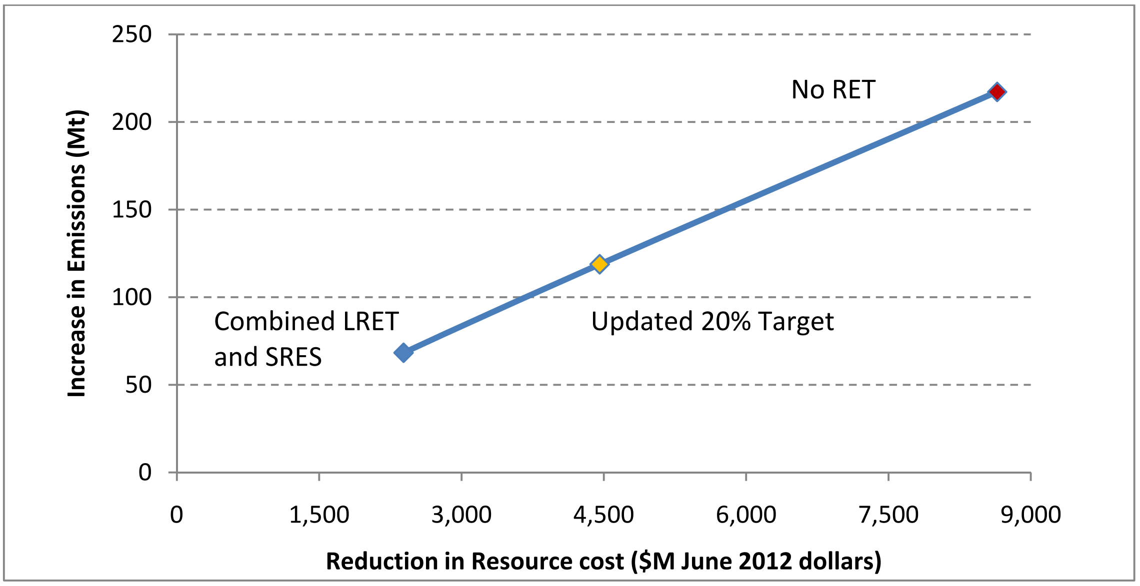


Table 3 and Figure 61 show that as the RET reduces, resource cost reduces and GHG emissions increase. The cost of abatement credited to “Reference Case 1”, ranges from $35/t to $40/t when compared against the reduced RET cases.

Under “Reference Case 1”, emissions vary in response to changes in carbon price. Under the higher carbon price, “Reference Case 2”, the changes to emissions are relatively small since the carbon prices only diverge for a few years. In the medium term, emissions are lower in “Reference Case 2”, and resource costs are higher, as existing gas-fired generation displaces some coal-fired generation in the merit order, and there is slightly more renewable generation developed. In the longer term however, there is little difference in the generation mix.

Under the “Zero Carbon Price” scenario, emissions increase substantially when compared to “Reference Case 1”, largely due to an increase in coal-fired generation. However, due to the elasticity of demand impact assumed in this case, demand is also higher in the “Zero Carbon Price” which leads to an increase in resource cost.

With “Low Demand”, both the GHG emissions and resource cost are reduced due to lower levels of generation.

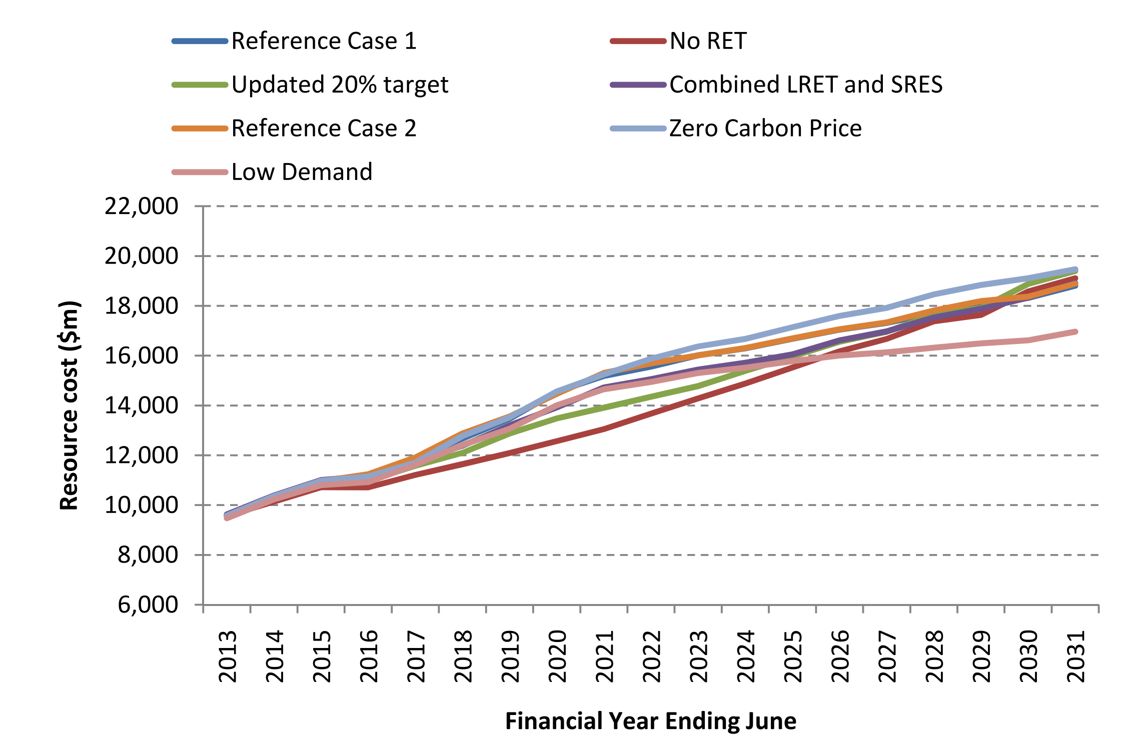
6.1.3. Resource Cost

The lower RET target drives a lower resource cost due to a reduced development of renewable generation to displace either gas or coal.

The trajectory of the resource costs between cases is shown below in Figure 61[13].

[13] These resource cost totals do not include fixed costs for existing units which do not retire. These costs would not vary between cases.

- **Figure 61 Resource cost comparison, June 2012 dollars**



Differences in resource costs between scenarios are mainly driven by new renewable generation displacing generation from existing coal and gas-fired generation. There is little need for additional thermal capacity in the first 10 years of the analysis due to the relatively low demand growth projected by AEMO and IMO. As renewable generation development approaches similar levels between the cases, the difference in resource cost narrows.

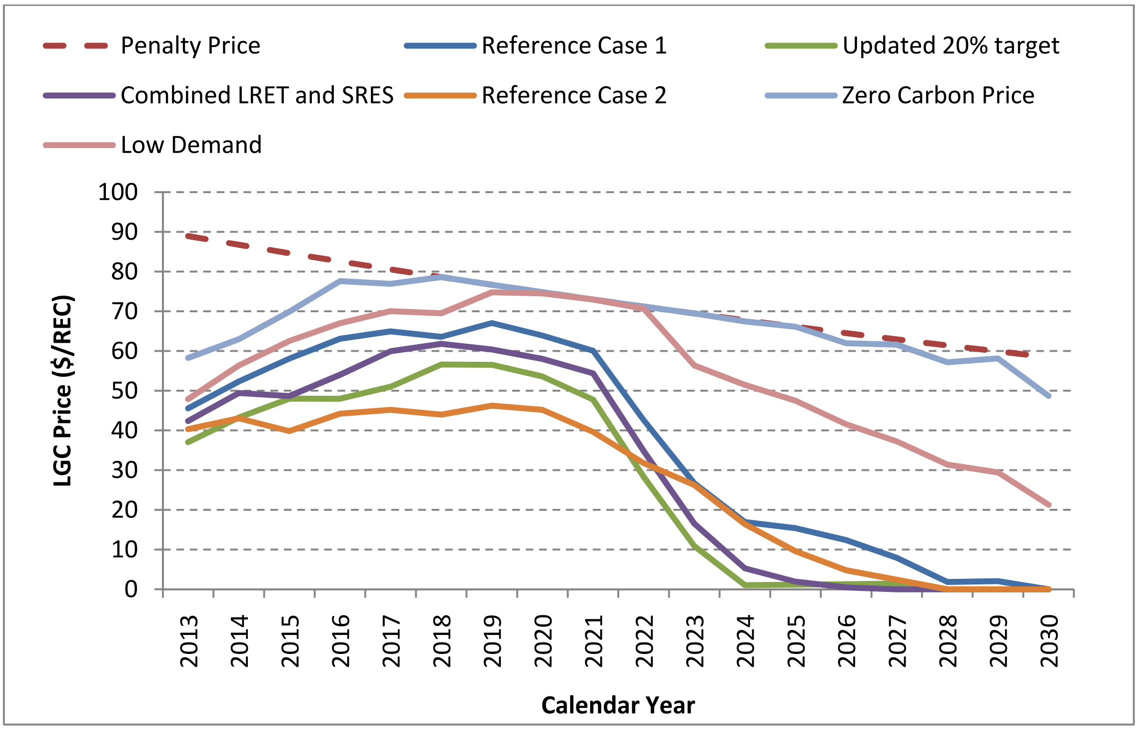
The "Zero Carbon Price" case has the highest resource cost due to the modelling of demand elasticity for this case, "Zero Carbon Price" has the largest demand of all cases and therefore the highest resource cost. Compared to "Reference Case 1", the NPV of resource costs for "Zero Carbon Price" case is $2 billion greater.

The "No RET" case has the lowest resource cost on an NPV basis, being $8.6 billion lower than "Reference Case 1".

6.1.4. LGC Prices

Higher RET leads to higher LGC prices as more renewable generation, with higher cost, is required to meet the target. This is illustrated in Figure 62. The tax effective penalty price was not reached for any of the medium demand and low carbon price scenarios examined. All targets were expected to be achieved.

Figure 62 LGC prices for each case



With a higher carbon price and resulting higher wholesale price, the LGC price fell as the support required from the RET for the renewable generation development reduced. Conversely, without a carbon price, the wholesale prices were lower putting upward pressure on the LGC price, and the LGC penalty price was reached in 2018. It was estimated that the penalty price would need to be approximately $3 higher in 2020 to ensure the renewable generation required in this case would be built. A target shortfall of 3,500 GWh is estimated as of 2020 in this scenario, although it is expected that development would occur post 2020.

The only other case where the penalty price was reached was in the “Low Demand” case. Again “Low Demand” results in lower wholesale prices leading to higher LGC prices to meet the RET target. Drawing from these observations, if a lower demand and a lower carbon price were to prevail in the period prior to 2020 then the existing RET target may not be met.

As a result of these LGC price variations, the certificate cost for the RET changes for the various cases. The certificate cost is calculated based on the cost of both the SRES and LRET schemes for all cases. In the “No RET” case, it is assumed that there is an ongoing cost for the existing commitments associated with the LRET scheme. The certificate cost includes an administration charge and market charges but is predominantly made up of the cost of the LGC and SRES.

The resultant certificate cost for the various cases is shown in Table 4.

- **Table 4 RET Certificate costs**

	RET Certificate cost ($/MWh)	
	CY2015	CY2020
Reference Case 1	6.7	12.8
Updated 20% Target	5.9	6.9
No RET	0.0	0.0
Combined LRET and SRES	6.7	12.3
Reference Case 2	6.1	10.1
Zero Carbon Price	7.9	14.9
Low Demand	7.2	15.0

In general, as the RET reduces, the certificate cost reduces. The exception is in the "Combined LRET & SRES" case where the small-scale renewable generators receive a higher certificate price, which leads to minimal difference in certificate costs overall. Given the current costs of solar PV, changes in certificate price were not a key driver of uptake of solar. Therefore, the 8,000 GWh initial estimate of solar PV changed only marginally in this "Combined LRET & SRES" case and did not have as much impact on the required contribution from large-scale renewable generation as originally anticipated.

6.1.5. Wholesale Prices

One of the key findings is that, in the current over-supplied electricity market environment, the greater the RET target, and the greater the renewable generation, the lower the wholesale market prices. This is driven by the additional supply in the system causing downward pressure on prices. Table 5 illustrates the changes in wholesale prices over time, for the seven cases considered.

- **Table 5 Wholesale price comparison, June 2012 dollars**

	Wholesale Price ($/MWh)			
Case	FY2014/15	FY2019/20	FY 2024/25	FY 2029/30
Reference Case 1	54.4	51.1	105.7	117.2
Updated 20% target	54.5	55.5	111.1	118.8
No RET	55.9	63.9	116.5	118.3
Combined LRET and SRES	54.5	53.0	108.7	118.8
Reference Case 2	54.4	71.7	106.7	118.9
Zero Carbon Price	53.8	36.9	57.3	66.4
Low Demand	51.7	42.1	77.2	98.8

By 2030, the wholesale prices are reasonably similar under the various RET targets. This reflects the development of renewable generation over the period tracking to a similar level. For the cases where the RET was varied, the greatest wholesale price difference was observed in the “No RET” case where, by 2020, the wholesale price was estimated to be approximately $12.9/MWh higher without RET. This increase in price is more than offset by the reduced certificate cost resulting in a reduction in the average annual household bill as discussed in the following section.

To ensure consistency and facilitate direct comparisons, the modelling has assumed the same level of price support for each case, except in the “Low Demand” case where some additional price support was needed for a longer period of time before prices recovered to new entry levels. The change in price between “No RET” and “Reference Case 1” may be reduced if existing generators have the opportunity to raise prices to maintain their profitability, when the renewable generators are not producing. Although it is expected that this may account for a small reduction in the price difference, the majority of the change is reflective of the change in supply balance.

As could be expected, the “Zero Carbon Case and “Low Demand” case both resulted in much lower prices over the period and similarly “Reference Case 2” resulted in higher wholesale prices for the period from 2016 to 2023 when the carbon price was higher than “Reference Case 1”.

6.1.6. Retail Prices and Household bills

Retail prices and household bills were most sensitive to changes in carbon price and demand. The impacts of the change in RET scenarios are low to minimal. Table 6 illustrates the contribution the RET certificate cost has to the average household bill (assuming 7 MWh average consumption), and the likely change in household bill over the period.

- **Table 6 RET Certificate Cost and average Household Impact of RET**

	RET Certificate Cost to Household ($/annum)		% of average Household Bill		Average change in Annual Bill ($) over the period^	NPV of Household bill Change ($) compared to Reference Case^
Case	**FY2015**	**FY2020**	**FY2015**	**FY2020**	**2013-2031**	**2013-2031**
Reference Case 1	47	89	3.0%	5.3%	-	-
Updated 20% target	41	49	2.6%	2.9%	0.4	9
No RET	0	0	0	0	-15	-154
Combined LRET and SRES	47	86	3.0%	5.1%	6	70
Reference Case 2	43	70	2.7%	3.9%	50	595
Zero Carbon Price	55	104	3.5%	6.6%	-208	-1,611
Low Demand	51	105	3.3%	6.5%	-101	-827

^positive value indicates an increase in the household bill.

In the extreme, without any future RET, a $15/annum reduction in household bill is expected over the period, compared to “Reference Case 1”. If the average household bill in 2020 for “Reference Case 1” is estimated to be $1700/annum, then this represents a decrease of approximately 0.9% in the average household bill for a 217 Mt increase in emissions.

In “Reference Case 2”, the RET certificate cost percentage of the average household bill falls in the period from 2016 to 2020 due to the lower LGC prices when compared to “Reference Case 1”.

One of the reasons that the expected impact on the average household bill is so modest is that the downward pressure on wholesale prices, driven by the increase in renewable generation, partially offsets the RET certificate costs resulting in a low net increase in retail prices. To ensure consistency in comparisons, the analysis has been conducted assuming the same bidding strategy is applied across all scenarios. There is the potential that, in response to lower wholesale prices, generators may attempt to change their bidding strategy in order to increase prices and increase their profitability. Changes to bidding strategies to support prices at levels closer to new entry will reduce the differences in wholesale prices observed between scenarios. However, higher wholesale electricity prices will lead to lower LGC prices assuming that the LGC price provides the subsidy, in addition to the electricity price, that is required to make the last installed (marginal) renewable energy generator to meet the LGC target economic without further subsidisation.

Therefore, the net impact on households resulting from a change in assumed bidding behaviour is unlikely to be significant. This was tested by analysing the outcomes of the scenarios of “No RET”, “Reference Case 1” and “Updated 20%” assuming the No RET wholesale prices applied in all cases. In addition the LGC prices were adjusted to reflect this change. This analysis showed that at the extreme with no change in wholesale price due to LRET, that the NPV of change in household bill with and without RET could be as much as $414 for the average household bill over the period to 2030-31 (compared to the current estimate of $154 per household). Similarly, comparing “Reference Case 1” against the “Updated 20% Target” case, the lower renewable target in “Updated 20% Target” would lead to an average annual decrease in the average household bill of $9, if the generator bidding strategies adopted resulted in wholesale prices being maintained at levels observed in the “No RET” case. This is equivalent to a decrease of approximately $73 for the average household bill on a NPV basis over the period to 2030-31 (compared to the current estimate of $9).

6.1.7. Impact on prices for Small to Medium Enterprises

Analysis was also undertaken to assess the LRET impact on the average Small to Medium Enterprise (SME) customer. The main difference between SME and residential retail prices was that the SME prices were derived assuming lower network costs and retail margins. This resulted in lower retail prices for SME customers, although the annual bill for the average SME is much larger and assumes 140 MWh average annual consumption[14].

Table 7 provides a summary of the estimated impact of the various scenarios on the SME retail price and annual bill. Per unit of electricity consumed, the changes in the SME bills are similar to those observed for residential customers. “Reference Case 2” results in the largest increase compared to “Reference Case 1” due to the higher carbon price assumed in this scenario. For the “No RET” case there is a decrease in the average SME bill of $337/annum when compared to “Reference Case 1”. This compares to the average annual SME bill over the period of $30,814 for “Reference Case 1”.

[14] Based on SKM MMA data for SME customer demand across all regions.

■ **Table 7 Average Retail Price and SME bill impacts**

	Average Retail price Change ($/MWh)	Average change in Annual SME Bill ($) over the period^	NPV of SME bill Change ($) compared to Reference Case^
Case		**2013-2031**	**2013-2031**
Reference Case 1	-	-	-
Updated 20% target	-0.1	-13	-2
No RET	-2.4	-337	-3,511
Combined LRET and SRES	0.8	113	1,314
Reference Case 2	6.8	958	11,476
Zero Carbon Price	-28.9	-4,050	-31,430
Low Demand	-13.8	-1,937	-15,908

^positive value indicates an increase in the SME bill.

6.1.8. Overview of results

The change in RET has both positive and negative impacts. The existing RET drives more renewable development which in the short term lowers wholesale prices and reduces the impact on household bills. A higher target allows more emissions to be abated earlier. On the other hand, higher targets increase resource costs. Even a small reduction in the target, as modelled in the “Combined LRET & SRES” case, provides a $2.4 billion lower resource cost (NPV). In this case, the emissions increase by 68 Mt with an effective cost of the additional emissions of $35/t.

A comparison of all cases relative to “Reference Case 1” is provided in Table 8. In Table 8 a negative value represents a decrease from “Reference Case 1”. In all the RET cases, the expected average change in retail prices is small and the NPV change in the average household bill is less than 1%, compared to “Reference Case 1”.

While the results of the “Low Demand” and “Zero Carbon Price” cases are not surprising, the results do indicate the potential issues faced with the existing target under these cases. In the “Zero Carbon Price” case, the low wholesale prices result in a LGC price equivalent to the penalty price by 2020. In the “Low Demand” case, a similar outcome is seen where the LGC price reaches the penalty price in one year (2021). In the case of a “Zero Carbon Price”, it is likely that there would be a RET shortfall of approximately 3,500 GWh by 2020.

In “Reference Case 2”, the implication for the existing target is that the LGC price should drop and make meeting the existing RET target easier.

A lower target such as the “Updated 20% Target” is expected to delay the development of renewable generation by approximately 5 to 6 years. With “No RET” the amount of renewable development is lower and the delay is substantially longer (i.e. up to10 years to reach the same levels). In the “Combined LRET & SRES” case, the amount of renewable development is only marginally less than in “Reference Case 1” by 2020 and is similarly delayed by 5 to 6 years. In a “Zero Carbon Price” environment further renewable development in the period from 2020 to 2030 is negligible.

- **Table 8 Change in key parameters compared to “Reference Case 1”, June 2012 dollars**

Case	NPV change in Resource cost ($M)	Change in Emissions (Mt)	Average change in RET certificate cost to 2031 ($/MWh)	Average Wholesale price change# ($/MWh)	Average Retail Price change# ($/MWh)	NPV of Household bill Change ($)^
Updated 20% target	-4,457	119	-3.9	3.4	0.1	9
No RET	-8,645	217	-9.7	6.7	-2.1	-154
Combined LRET and SRES	-2,390	68	-1.1	1.7	0.9	70
Reference Case 2	437	-12	-1.9	7.9	7.1	595
Zero Carbon Price	2,035	137	1.5	-27.7	-29.7	-1,611
Low Demand	-5,938	-349	1.7	-13.7	-14.4	-827

^NPV over 2013-2031 period assuming a 7% discount rate and an average annual household consumption of 7 MWh,

average for period 2013-2031

Appendix A Assumptions

A.1 Energy Demand Forecast

A significant factor in how the RET will perform will be the underlying energy forecast for the NEM and other regions. In regard to the NEM the latest AEMO[15] energy and demand projections were used (August 2012).

- EF1 – AEMO Low growth energy forecast
- EF2 – AEMO Medium growth energy forecast

These forecasts are net of assumed energy contribution from solar PV. Therefore, it is necessary to add these assumptions back onto the forecasts in order to assess the true native demand and to model alternative market scenarios. It was also assumed that the solar hot water (SHW) uptake is included in the native demand forecast and hence this was not explicitly modelled in the electricity market forecasting. The native demand forecasts for each region of the NEM for each case are shown in Table 9 for the Medium growth and Table 11 for low growth.

15 http://www.aemo.com.au/en/Electricity/Planning/Related-Information/2012-Planning-Assumptions

▪ **Table 9 NEM energy demand by region for medium case**

Energy demand by region – Medium Growth							
Fin Year	**Victoria**	**New South Wales**	**South Australia**	**Tasmania**	**Queensland**	**Total NEM**	**Total Australian (GWh)**
2012	47318	72334	13089	10682	49183	192606	219420
2013	48467	71638	13570	10799	50619	195093	220726
2014	49051	72664	13821	10849	52507	198893	225659
2015	49964	74048	14063	10956	55155	204185	231691
2016	50884	75227	14146	11120	58890	210267	237838
2017	51640	76203	14340	11308	61225	214716	243392
2018	52392	77660	14470	11416	62761	218699	247879
2019	53272	78368	14750	11471	63719	221580	251075
2020	54110	79350	14931	11552	64560	224502	254555
2021	55016	80447	15173	11703	65842	228181	258595
2022	55778	81492	15304	11900	66765	231238	262215
2023	56356	82381	15404	12075	67291	233507	264748
2024	56787	83169	15497	12272	67833	235558	267271
2025	57385	83958	15623	12427	68824	238217	270315
2026	58399	84580	15776	12549	70311	241614	274078
2027	59349	85212	15938	12634	71709	244842	277583
2028	60314	86174	16089	12739	72667	247983	281022
2029	60894	86931	16177	12822	73813	250638	284070
2030	61349	87231	16272	12959	74788	252599	286415
2031	61392	88026	16375	13083	75504	254380	288614
2032	61435	88828	16487	13209	76313	256272	290983
2033	61478	89638	16608	13335	77130	258189	293360
2034	61521	90455	16738	13463	77956	260134	295431
2035	61565	91279	16877	13592	78791	262105	297528
2036	61607	91887	17026	13686	79375	263582	299156
2037	61650	92665	17320	13807	80156	265597	301300
2038	61693	93442	17614	13928	80936	267613	303391
2039	61736	94219	17907	14050	81716	269628	305536
2040	61779	94997	18201	14171	82496	271643	307704

In case of the SWIS, the IMO 2012 forecasts were used, as published in the 2012 Statement of Opportunities. For the other regions (NWIS, DKIS) the forecasts are based on SKM assessment of likely demand growth in these regions. The forecasts for these systems are shown in Table 10 for medium growth and Table 12 for low growth.

- **Table 10 Other Non NEM systems - Medium Energy Demand**

Financial Year End	SWIS (GWh)	NWIS (GWh)	Northern Territory (GWh)	Mt Isa (GWh)	Non-NEM Total (GWh)
2012	19377	3081	1869	2487	26814
2013	17688	3500	1930	2516	25633
2014	18382	3883	1978	2523	26766
2015	18763	4077	2027	2639	27506
2016	19185	4094	2088	2204	27571
2017	19837	4236	2136	2466	28676
2018	20202	4270	2197	2511	29180
2019	20339	4307	2258	2591	29495
2020	20650	4352	2306	2745	30052
2021	21009	4391	2342	2672	30414
2022	21366	4426	2403	2781	30977
2023	21546	4474	2440	2781	31241
2024	21921	4510	2500	2781	31713
2025	22234	4534	2549	2781	32098
2026	22547	4539	2597	2781	32464
2027	22860	4539	2634	2708	32741
2028	23173	4475	2682	2708	33039
2029	23486	4507	2731	2708	33432
2030	23799	4542	2767	2708	33817
2031	24112	4610	2804	2708	34234
2032	24425	4714	2864	2708	34711
2033	24738	4811	2913	2708	35171
2034	24739	4888	2961	2708	35297
2035	24740	4965	3010	2708	35423
2036	24741	5066	3059	2708	35574
2037	24742	5157	3095	2708	35703
2038	24743	5196	3131	2708	35778
2039	24744	5276	3180	2708	35908
2040	24745	5367	3241	2708	36061

- **Table 11 NEM energy demand by region for Low case**

Demand by region – Low Growth							
Fin Year end	**Victoria**	**New South Wales**	**South Australia**	**Tasmania**	**Queensland**	**Total NEM**	**Total Australian (GWh)**
2012	47318	72334	13089	10682	49167	192591	218741
2013	47487	71182	13218	10000	52654	194542	219689
2014	47863	71793	13254	9806	53917	196634	222908
2015	48553	72256	13261	9669	55881	199620	226365
2016	49207	72849	13262	9643	57961	202922	229528
2017	49745	73220	13304	9777	60006	206051	233491
2018	50347	74094	13396	9862	61318	209017	236809
2019	51001	74131	13527	9896	61741	210296	238331
2020	51590	74490	13643	9946	62062	211732	240132
2021	52248	75077	13821	10054	62720	213920	242456
2022	52776	75456	13894	10217	63379	215722	244513
2023	53215	75885	13946	10366	63496	216909	245788
2024	53486	76235	13990	10540	63627	217877	246980
2025	53858	76483	14060	10662	64465	219528	248783
2026	54293	76560	14136	10736	65530	221255	250642
2027	54860	76600	14231	10785	66482	222958	252388
2028	55614	77016	14314	10854	66879	224676	254170
2029	55994	77344	14344	10907	67698	226287	255940
2030	56314	77545	14395	11025	68215	227494	257298
2031	56354	78252	14459	11131	68503	228698	258685
2032	56393	78965	14536	11238	69206	230338	260568
2033	56433	79685	14626	11345	69917	232006	262462
2034	56473	80411	14730	11454	70635	233702	264363
2035	56512	81144	14847	11564	71361	235428	266293
2036	56551	81684	14978	11644	71869	236726	267820
2037	56591	82375	15236	11747	72547	238496	269797
2038	56630	83066	15494	11850	73226	240266	271721
2039	56670	83757	15753	11953	73904	242037	273698
2040	56709	84448	16011	12056	74582	243807	275700

- **Table 12 Other Non NEM systems - Low Energy Demand**

Financial Year End	SWIS (GWh)	NWIS (GWh)	Northern Territory (GWh)	Mt Isa (GWh)	Non-NEM Total (GWh)
2012	18713	3081	1869	2487	26150
2013	17202	3500	1930	2516	25147
2014	17890	3883	1978	2523	26274
2015	18002	4077	2027	2639	26745
2016	18220	4094	2088	2204	26606
2017	18601	4236	2136	2466	27440
2018	18814	4270	2197	2511	27792
2019	18879	4307	2258	2591	28035
2020	18998	4352	2306	2745	28400
2021	19131	4391	2342	2672	28536
2022	19180	4426	2403	2781	28791
2023	19184	4474	2440	2781	28879
2024	19312	4510	2500	2781	29104
2025	19391	4534	2549	2781	29255
2026	19470	4539	2597	2781	29387
2027	19549	4539	2634	2708	29430
2028	19628	4475	2682	2708	29494
2029	19707	4507	2731	2708	29653
2030	19786	4542	2767	2708	29804
2031	19865	4610	2804	2708	29987
2032	19944	4714	2864	2708	30230
2033	20023	4811	2913	2708	30456
2034	20103	4888	2961	2708	30661
2035	20182	4965	3010	2708	30865
2036	20261	5066	3059	2708	31094
2037	20340	5157	3095	2708	31301
2038	20419	5196	3131	2708	31454
2039	20498	5276	3180	2708	31662
2040	20577	5367	3241	2708	31893

A.2 Gas prices

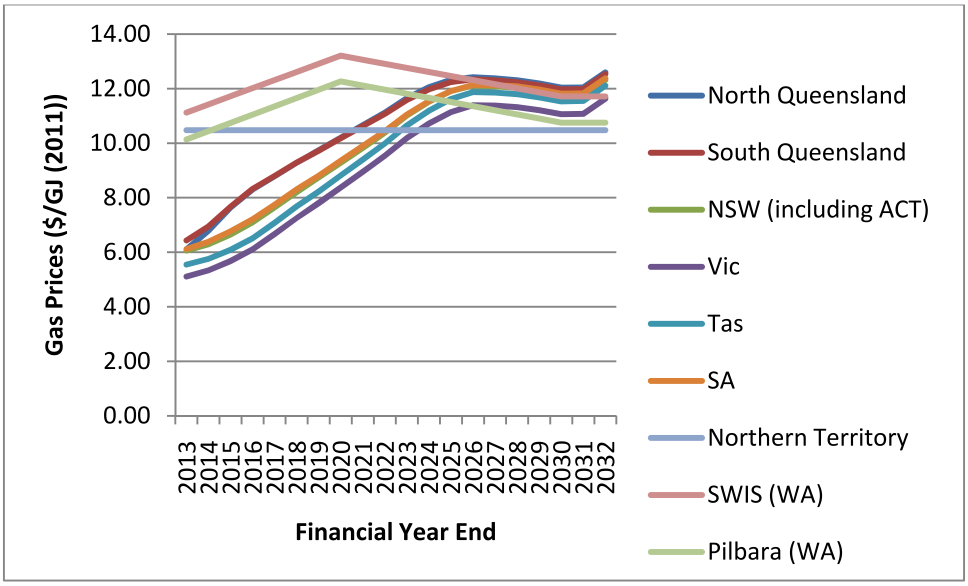
Regional gas prices developed by ACIL Tasman for the AEMO National Transmission development planning were used for this analysis. These are also consistent with the Bureau of Resources, Energy and Economics work on the Australian Energy Technology Assessment (ACIL Tasmania supplied both BREE and AMEO). The numbers used for the analysis are summarised in Table 13 and Figure 63.:

▪ **Table 13 Gas prices across Australia – AEMO scenario 3, sensitivity 4**

Region ($/GJ – $2011)									
Financial Year End	North Queensland	South Queensland	NSW*	Vic	Tas	SA	Northern Territory	SWIS (WA)	Pilbara (WA)
2013	6.11	6.43	6.06	5.11	5.54	6.12	10.48	11.12	10.13
2014	6.79	6.95	6.29	5.34	5.76	6.39	10.48	11.42	10.44
2015	7.64	7.67	6.64	5.67	6.09	6.77	10.48	11.72	10.74
2016	8.30	8.32	7.10	6.10	6.51	7.21	10.48	12.02	11.05
2017	8.79	8.80	7.64	6.67	7.08	7.74	10.48	12.32	11.35
2018	9.29	9.29	8.22	7.26	7.68	8.30	10.48	12.61	11.66
2019	9.73	9.72	8.73	7.80	8.23	8.81	10.48	12.91	11.96
2020	10.20	10.18	9.29	8.38	8.81	9.36	10.48	13.21	12.27
2021	10.66	10.63	9.83	8.95	9.39	9.89	10.48	13.06	12.12
2022	11.12	11.07	10.39	9.54	9.99	10.44	10.48	12.91	11.96
2023	11.65	11.59	11.01	10.19	10.65	11.05	10.48	12.76	11.81
2024	12.06	11.98	11.52	10.72	11.19	11.54	10.48	12.61	11.66
2025	12.32	12.24	11.91	11.14	11.62	11.91	10.48	12.46	11.51
2026	12.42	12.34	12.12	11.39	11.87	12.14	10.48	12.31	11.36
2027	12.38	12.30	12.09	11.38	11.86	12.13	10.48	12.16	11.21
2028	12.31	12.24	12.02	11.32	11.79	12.08	10.48	12.01	11.06
2029	12.19	12.12	11.91	11.21	11.68	11.97	10.48	11.86	10.90
2030	12.04	11.97	11.75	11.06	11.53	11.82	10.48	11.71	10.75
2031	12.04	11.98	11.76	11.08	11.55	11.83	10.48	11.71	10.75
2032	12.60	12.54	12.32	11.63	12.10	12.38	10.48	11.71	10.75

*(including ACT)

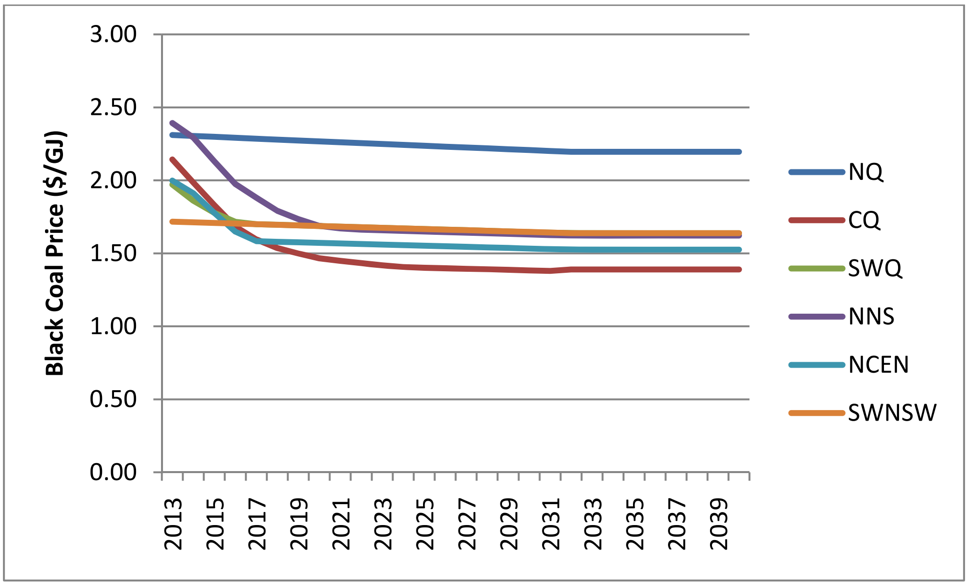
▪ **Figure 63 Gas prices across regions**



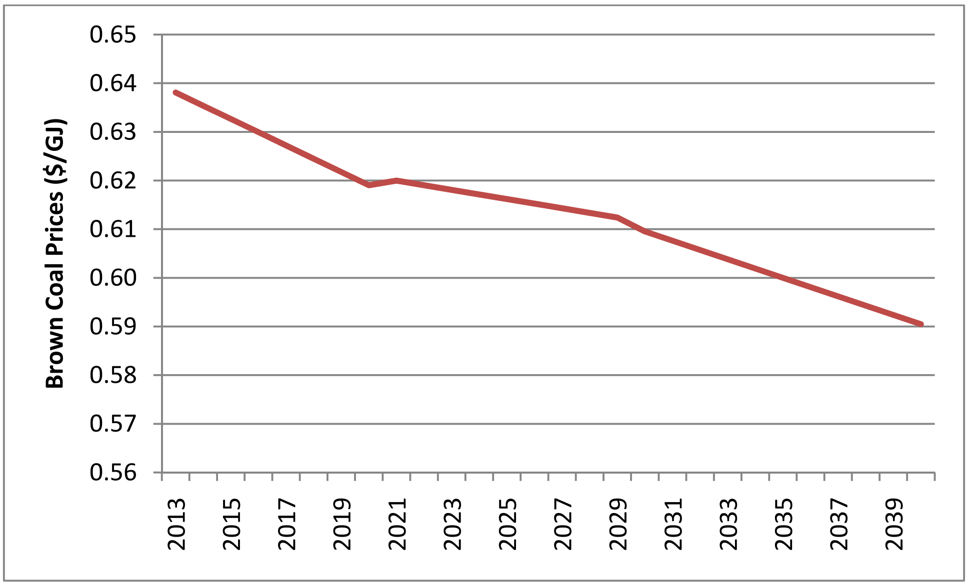
A.2.1 Coal Prices

The coal prices were sourced from the Australian Energy Technology Assessment by BREE and ACIL Tasman. The black coal prices shown in Figure 64 are the same as those used in AEMO's scenario 3. Figure 65 illustrates the Victorian brown coal price that was used in this study.

- **Figure 64 Black Coal Price by region**



- **Figure 65 Brown Coal Prices (Victoria)**



A.2.2 Technology Costs

The technology costs used in this study are those compiled by SKM MMA and are illustrated in Appendices (A.4 for renewable energy). In adopting these values comparisons were made with the most recently published data in the AETA and AEMO. The data supplied for that work was produced by Worley

Parsons[16]. On review of the methodology used by Worley Parsons, it is the same as that used by SKM MMA. Therefore the results should be broadly consistent, although some assumptions may vary slightly.

Further, a comparison of the capital cost estimates has been compared with the work reported in the Australian Energy Technology Assessment (AETA) by BREE and while there are differences the SKM MMA assumed numbers appear consistent. This is also illustrated in AETA in Table 5.2.2 which compares the AETV 2012 values with numerous studies including the SKM MMA values in the 2011 Treasury modelling. As is noted in the AETA:

> "In general, a comparison of capital costs does not reveal substantial differences between technologies"

The capital cost of a technology typically represents a major component of the overall cost of electricity generation. The comparison of capital costs provides a good insight into the likely levelised costs and as such the assumptions of technology costs should be broadly similar. Hence, rather than the additional work needed to further understand and input the AETA data into the SKM MMA model, it was considered better to use the current SKM MMA estimates as the differences in the study outcomes are likely to be marginal.

One area that was seen to be different in AETA from past work was the estimated cost of photovoltaic systems at the time. BREE note this in the report and indicate that:

> "cost of photovoltaic modules has fallen by approximately 50 per cent over the past 2 to 3 years. At present, modules comprise of approximately one-half of the capital cost of photovoltaic systems."

When comparing these costs to the SKM values for PV non tracking the differences are $3380/kW (AETA) compared to $3,989/kW (SKM MMA). On further exploration the AETA number is based on a 100 MW PV installation while the SKM is based on a 10 kW installation. The economies of scales alone are likely to mean these numbers are likely to be reasonably similar so no change was made for this study.

It was also noted in the AETA that the 2030 geothermal costs are substantially higher than the SKM MMA numbers. Again, comparing the two numbers showed the AETA was between 30% to 50% higher for hot sedimentary aquifer installation. It is expected that geothermal generation will play a limited role in the results even using the current SKM MMA values. Again, the existing SKM MMA values for geothermal were used for this study.

Over time the costs of the technologies will decrease due to the learning rates of various technologies. These are modelled in Strategist and the assumptions on learning rates are illustrated in Figure 70.

In terms of projected capital costs out to 2030, AETA LCOEs are similar to other studies for most technologies. A notable difference between the AETA estimates and the earlier studies is the estimated capital cost of photovoltaic systems. It is now expected that the substantial cost reduction trend experienced in recent years will continue to occur into the future. Another noticeable difference relates to the capital cost of hot rock (i.e. enhanced) geothermal systems. The AETA LCOE for this technology are

---

16 http://www.aemo.com.au/en/Electricity/Planning/Related-Information/~/media/Files/Other/planning/WorleyParsons_Cost_of_Construction_New_Generation_Technology_2012%20pdf.ashx

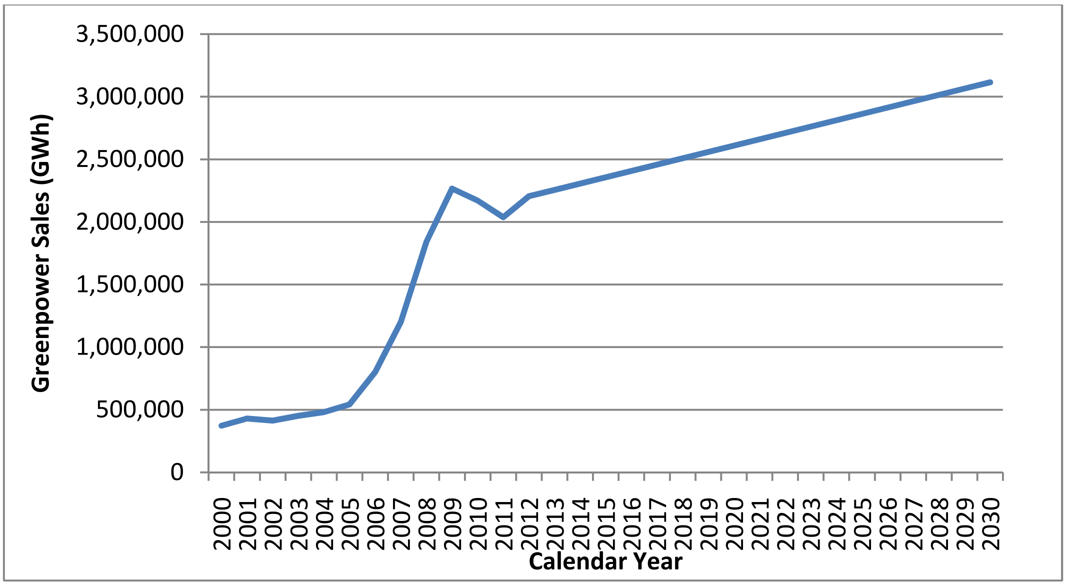
substantially higher than the estimates made by ACIL Tasman, SKM-MMA and ROAM are at the high end of the cost range estimated by EPRI. The major reason for the cost difference arises from a more recent and better informed appraisal of drilling costs that comprise a major component of the capital cost of hot rock geothermal systems.

A.3 Other Renewable schemes

Greenpower and Fit schemes were modelled as continuing in their current form. The Fit schemes were modelled explicitly in the DOGMMA model (refer to Appendix A.8.2 for detail) with the expected capacity and energy netted off the native demand modelled in Strategist. Note the most recent changes to Fit schemes in Queensland and Victoria have been included in the modelling.

Greenpower expected sales are shown in Figure 66 applying a 4-year trend to extend historical sales.

- **Figure 66 Greenpower Sales Assumption**



A.4 Renewable Technology Assumptions

A.4.1 Renewable Energy Data Base

SKM MMA has developed a data base of existing, committed and developing projects. Existing projects are those that are in operation or have been in operation since 1997. Committed projects are those under construction or that have achieved financial close. Prospective projects cover potential new projects in various stages of development.

Amongst other objectives, the data base is used to provide input data into the Renewable Energy Market Model Australia (REMMA) model. Only projects greater than 30 kW are included for this purpose. Details of smaller scale embedded generation projects are included directly in the Distributed and On-site Generation Market Model Australia (DOGMMA).

The data base contains details on location, capacity, historical and expected generation, potential LGC creation, year commenced operation, economic life, retirement date, period of construction, capital cost, transmission connection costs, variable and fixed operating costs, fuel costs (if applicable), marginal loss factors, direct employment and construction jobs created. The data can be used to calculate short and long run marginal costs of generation.

The data base was populated by information and data sourced from:

- Clean Energy Regulator.
- Annual reports of generating companies and retailers.
- ASX announcements.
- AEMO and IMO data bases.
- Environmental impact statements.
- Media releases.

The data base contains details of around 699 projects. Summary details of the projects covered are shown in Table 14. Not all projects contained in the data base are eligible to earn certificates. For example, only a portion of the generation from the pre-existing hydro-electric projects is eligible to generate certificates.

- **Table 14 Summary details of renewable energy projects**

Technology	Number			Capacity, MW		
	Existing	Committed	Proposed	Existing	Committed	Proposed
Agricultural Waste	4	0	5	24	0	37
Bagasse	32	2	3	501	49	118
Black Liquor	3	0	0	77	0	0
Landfill Gas	60	0	2	154	0	22
Municipal Solid Waste	6	0	8	14	0	146
Sewage Gas	23	0	3	37	0	7
Wood / Wood Waste	15	0	16	54	0	570
Geothermal	1	0	8	0	0	627
Hydro	115	6	11	7,366	273	239
SHW	0	0	0	0	0	0
Solar / PV	69	9	22	30	499	1,633
Wave	3	0	2	22	0	2
Wind	74	10	185	2,221	1,013	19,787
Wet waste	1	0	1	0	0	4
Wheat/ethanol plant	0	0	0	0	0	0
Total	406	27	266	10,498	1,834	23,191

Note: existing projects will include projects no longer in operation. Source: SKM MMA renewable energy data base constructed using data from various published sources.

A working assumption for this study is that only known and prospective projects are included in the analysis. A further filter was applied and only those projects with a high likelihood of being developed before 2020 would be included in the analysis, unless directly supported by Government support funds (ARENA, Solar Flagships, and so on). Projects which require further technological development (except where this would be funded under Government demonstration programs) or the development of which would require substantial upgrades of the transmission grid were assumed not to proceed until after 2020. This filtering precluded the use of geothermal projects beyond those projects announced, ocean based technologies and some large-scale wind farms[17], except in scenarios where explicit support for these technologies is included as a scenario parameter (for example, under the banding policy scenario).

Wood waste projects based on native forest resources were also excluded as they are no longer eligible to create LGCs.

Land planning amendments have recently been enacted in Victoria and South Australia. Similar amendments are being considered in NSW. The amendments require approval of all dwelling owners within two kilometres (in the case of Victoria and NSW) or one kilometre (in the case of South Australia). The assumption used in this study is that the amendments reduces the size of yet to be approved wind projects by around 20% (reflecting that not all the proposed turbines will receive full approval).

With these restrictions, the available capacity from prospective projects to meet future growth in the target by technology is shown in Table 15. Eligible generation for these projects is shown in Table 16.

The data indicate three features:

- There are more than enough available projects to meet the projected increase in the target. Projects under development amount to around 18,000 MW.
- The bulk of the projects are wind energy generation. This technology makes up around 85% of the generation from prospective projects.
- The majority of projects are located in the south east Australia mainly due to the predominance of favourable wind sites and projects in these States.

Table 15 Capacity of prospective projects included in the modelling, MW

Technology	Qld	NSW/ACT	Vic	Tas	SA	WA	NT	Total
Agricultural Waste	5	1	0	0	0	31	0	37
Bagasse	88	30	0	0	0	0	0	118
Black Liquor	0	0	0	0	0	0	0	0
Landfill Gas	0	20	2	0	0	0	0	22
Municipal Solid Waste	0	5	14	21	0	60	0	100
Sewage Gas	0	0	2	5	0	0	0	7
Wood Waste	62	0	0	0	28	145	0	234
Wet waste	0	4	0	0	0	0	0	4
Geothermal	0	0	12	0	0	0	0	12

[17] Assumed to be wind farms located in the Eyre Peninsula (South Australia), central and north Queensland, upper mid- west region of Western Australia and remote parts of NSW.

Technology	Qld	NSW/ACT	Vic	Tas	SA	WA	NT	Total
Hydro	30	0	11	198	0	0	0	239
Solar / PV	310	278	342	0	41	300	0	1,271
Wave	0	0	0	0	0	0	0	0
Wind	1,342	5,420	4,507	525	4,109	550	0	16,454
Total	1,837	5,759	4,890	749	4,178	1,086	0	18,498

Notes: Solar/PV projects include projects awarded grants under the Solar Flagships Program (e.g. the Solar Dawns solar thermal plant in Queensland and the AGL PV project in NSW). Excludes projects based on technologies which are not likely to be developed by 2020 (unless likely to be funded by Government support programs) or which require extensive upgrades of the transmission network for its output to reach load centres. Source: SKM MMA renewable energy data base constructed using data from various published sources

▪ **Table 16 Expected generation from prospective renewable energy projects, GWh**

Technology	Qld	NSW/ACT	Vic	Tas	SA	WA	NT	Total
Agricultural Waste	17	6	0	0	0	247	0	269
Bagasse	598	202	0	0	0	0	0	800
Black Liquor	0	0	0	0	0	0	0	0
Landfill Gas	0	59	9	0	0	0	0	68
Municipal Solid Waste	0	26	92	148	0	429	0	695
Sewage Gas	0	0	9	26	0	0	0	35
Wood Waste	247	2	0	0	191	1,046	0	1,486
Wet waste	0	0	88	0	0	0	0	88
Geothermal	0	0	88	0	0	0	0	88
Hydro	105	0	36	512	0	0	0	653
Solar / PV	821	695	629	0	60	1,243	0	3,448
Wave	0	0	0	0	0	0	0	0
Wind	3,435	13,775	12,831	1,598	10,906	1,651	0	44,197
Total	5,223	14,787	13,694	2,284	11,157	4,616	0	51,761

A.4.2 Costs

Costs of renewable generation covered for each project in the data base cover the following items:

- Capital costs. These costs are typically based on the announcements made during project development or achievement of financial close. The assumption is made that published costs refer to capital costs of the renewable energy generator and do not include interest during construction or transmission connection costs unless specific details of these costs have been provided. Costs are escalated to mid 2012 dollar terms using the Australian CPI for all capital cities. A separate escalation is applied to account for trends in underlying capital costs since the announcement was made using the Marshall Capital Cost Index for power projects or from data available from REN21 on movements in wind and solar PV capital costs. For projects where no data on capital costs is available, the capital cost is derived using a curve fitted through the capital costs for the relevant technology (as function of capacity).

- Transmission connection costs. Data on connection costs are based on available connection cost data published by project proponents or by network service providers.
- Fuel costs, which mainly applies to biomass projects. Published data on fuel costs tends to be limited. For project utilising waste by-products as fuel, the fuel cost comprises a handling and treatment charge. For other fuel sources, the cost is constructed from published estimates of the opportunity cost (that is, the value of the fuel in alternative uses), transport, handling and treatment costs. Fuel costs for projects dispatched in the NEM are cross-checked to determine whether they are aligned with the bids of these generators.
- Non-fuel operating and maintenance costs. Limited published data is available on non–fuel operating and maintenance costs. Where published data is not available, fixed costs are constructed from the level of direct employment at each facility multiplied by average award rate data for the electricity generation industry. Variable O&M costs are small and are assumed to range from $8/MWh to $10/MWh. Published data on labour and material costs for companies which specialise in renewable generation are used to cross-check these constructed costs.
- Ancillary service costs to cover for the impact of intermittency of some generation sources and for pumping costs for geothermal projects. Ancillary costs for wind generation vary from $6/MWh to $9/MWh, based on market data for ancillary services available from AEMO.

A.4.3 Capital costs

Current capital costs by technology are shown in Figure 67 to Figure 69. The estimates are based on project proponent estimates of the project capital cost. The costs are assumed to be turnkey costs for installing the plant and cover the cost of approval and development, equipment and installation. Interest during construction and transmission costs are treated separately and are not included in the turnkey cost estimates.

Capital costs for biomass projects are between $2,300/kW to $14,200/kW with an average of around $5,000/kW. The wide range reflects several factors but particularly the presence of some projects based on new technologies with first of a kind capital costs. Capital costs for wind projects vary from $1,600/kW to $11,700/kW, with an average of around $2,500/kW. The high cost projects reflect either small isolated wind projects or projects with a storage (fly wheel) component. Capital costs for solar projects (PV and solar thermal) range from $3,200/kW to $11,300/kW, with an average of $5,900/kW for all projects but around $4,500/kW if projects less than 50 kW are excluded. The high values for capital costs for solar technologies reflect demonstration projects of new technologies, particularly new solar thermal technologies or projects developed in remote areas, which tend to have high installation costs.

- **Table 17 Capital cost data, $/kW**

	Biomass	Wind	Solar
Minimum	2,264	1,570	3,170
Maximum	14,200	11,703	11,321
Mean	4,997	3,264	5,901

Source: SKM MMA

Subsidies by State and Federal Government have been offered for some renewable energy projects. When used to project LGC prices, these subsidies are deducted from the capital cost estimates to arrive at a net capital cost. In relation to specific subsidy programs managed by the Australian Renewable Energy Regulator (ARENA), the following projects are deemed to proceed and will act as price takers in the LGC market:

- **Figure 67 Capital costs for prospective wind projects**

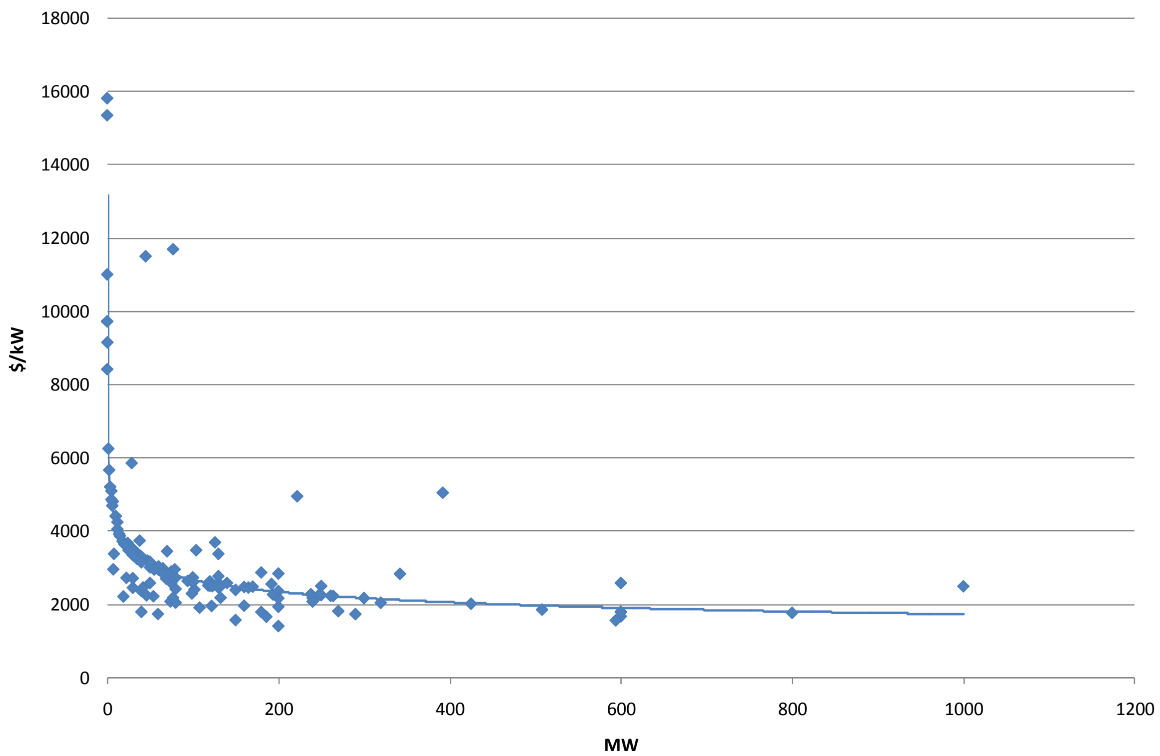


Figure 68 Capital costs for prospective biomass projects

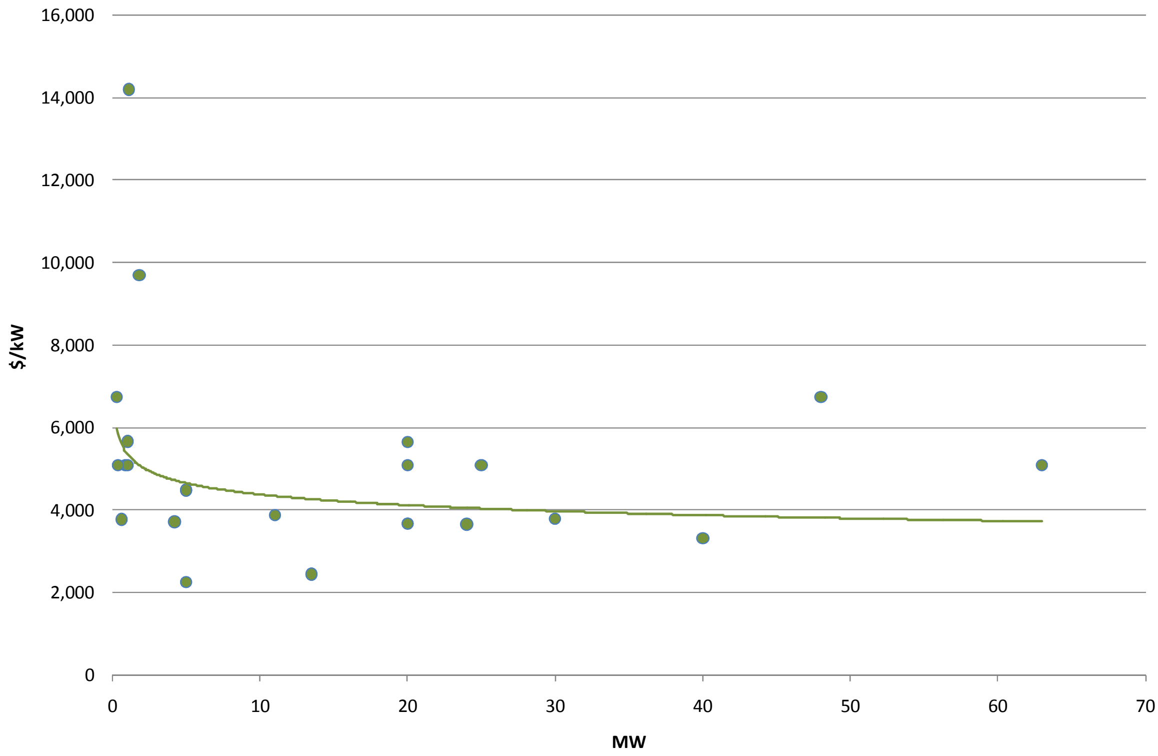
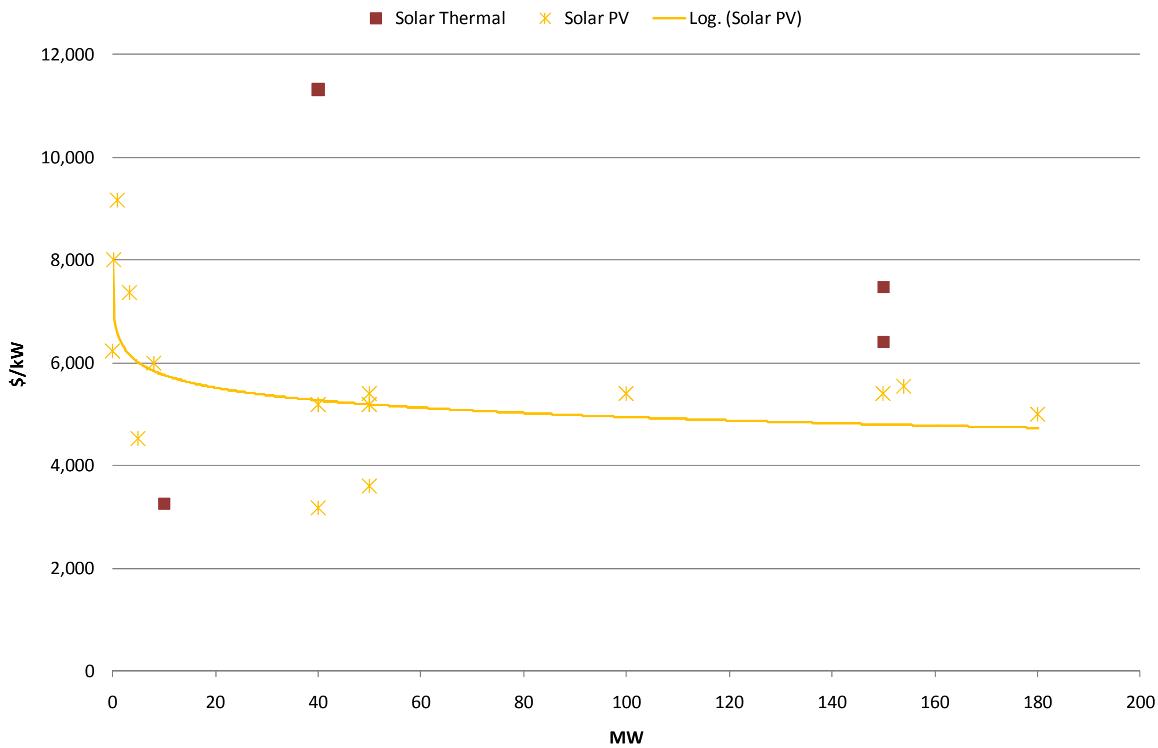


Figure 69 Capital costs for prospective solar projects



Source: SKM MMA renewable energy data base

- The first phase of the Solar Flagships program has been modelled explicitly. With the RET scheme, it is assumed that the two projects funded under the first phase (the 250 MW solar thermal Solar Dawn project in Queensland and the AGL 159 MW solar PV project in Broken Hill and Nyngan) proceed as planned.
- CS Energy's Kogan Creek Solar Boost project, which will provide an extra 44 MW of capacity at the coal-fired power station.

These projects are assumed to proceed because either construction has commenced or there is a high likelihood of off-take agreements being achieved. Other projects, such as the $230 million Solar Oasis solar thermal project in Whyalla[18] and Solar Silex's large scale solar concentrator facility in Mildura[19], will only proceed if sufficient revenue can be earned from electricity and LGC sales to recover sufficient returns on the remaining investment not funded by Government.

The impact of funding under the Clean Energy Finance Corporation is more difficult to model. The Corporation will provide low interest loans, equity injection or loan guarantees, with a preference for low interest loans, for projects which face financial market failures or hurdles to proceed. Around $10 billion is to be allocated, around $2 billion per year over a 5 year period commencing from 1 July 2013. At least $5 billion is to be allocated to renewable energy projects, but this could include enabling technologies.

We have assumed that:

- $5 billion is dedicated to renewable energy and enabling technologies.
- We assume 75% of this (or $3.75 billion) is allocated to renewable energy for electricity generation (as opposed to direct combustion or transport fuel).
- Fifty per cent of this (or $1.88 billion) is for enabling technologies such as network extensions (enabling access, say, to wind, geothermal and solar farms in remote locations) and storage technologies. We have used a high proportion for enabling technologies because such developments can help assist the development of a range of renewable energy technologies, there are a range of market barriers affecting enabling technologies and because constraints on enabling technologies are preventing least cost uptake.
- The remaining fifty per cent ($1.88 billion) is allocated to novel (nearly commercialised) technologies such as solar thermal, geothermal, new biomass and ocean technologies.
- The CEFC provides lending for up to one-third of the total investment in the project at a rate set at the Treasury 10 year bond rate (currently just under 4% in nominal terms).

Capital costs vary as a function of capacity, as can be seen from the scatter plots shown above[20]. For biomass projects, unit capital costs (i.e. on a $/kW basis) flatten out after around 5 MW. For wind projects, unit capital costs flatten out after around 150 MW to 200 MW. For solar projects, the costs flatten out around 5 MW. Transmission connection costs may increase the range of when unit capital costs flatten out.

---

[18] A 40 MW project located, which is to receive $60 million from ARENA should it proceed.

[19] This is a 100 MW project reported to cost around $500 million. The project has been awarded around $125 million in Federal and Victorian funding should it proceed.

[20] The fitted lines in the scatter plot are derived from the options for curve fitting provided in Excel. They should be treated only as a guide to or suggestive of the relationship between unit capital costs and capacity. For most technology categories (especially solar and biomass) not enough data is available to develop a precise relationship.

Assumed capital cost trends are shown in Figure 70. The cost trends apply to the proportion of installed costs from equipment purchased overseas. Technology costs are expected to decline for most of the technologies, reflecting long term trends. The actual rate of decline can differ as there can be variations due to stalled or accelerated development, and differing rates of economies of scale.

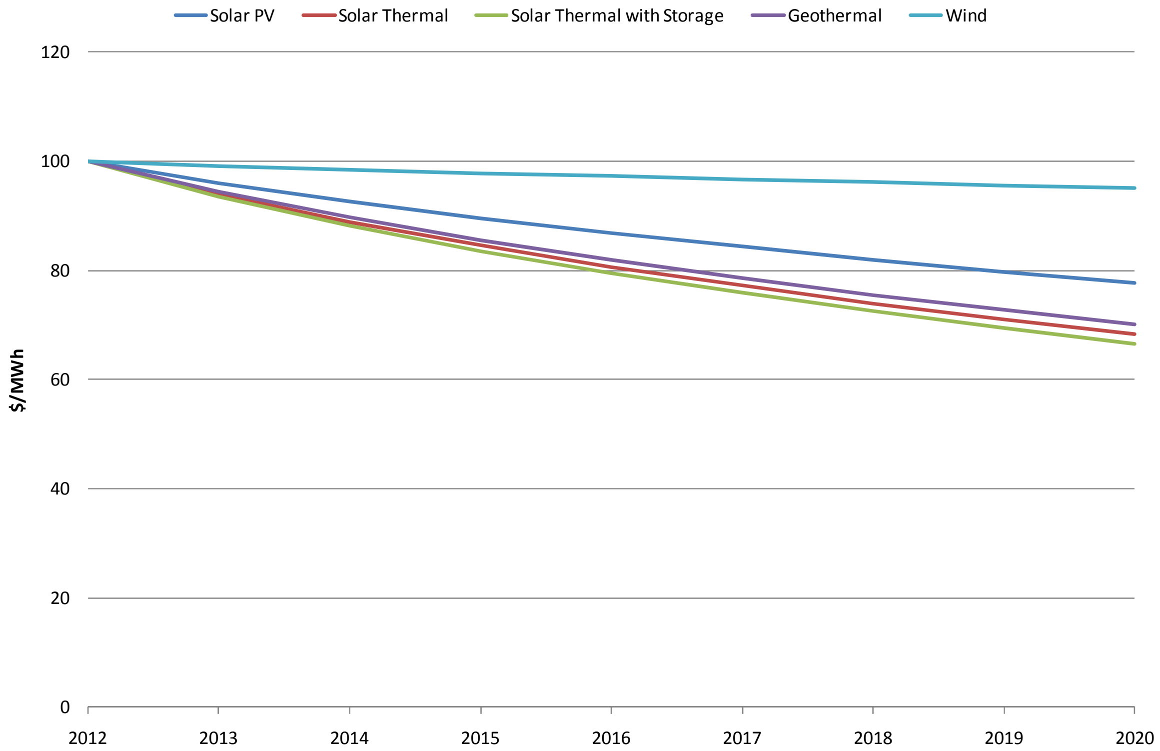
The decline in technology costs over time is reflected in a power factor equation:

$TC_t = TC_{t0} * e^{pf}$

Where TC_t is the technology cost (in \$/kW), TC_0 is the technology cost in 2011, e is the exponential and pf is the power factor.

The underlying assumption for this portion of installed costs is that uptake in Australia has little influence on the rate of cost decline.

- **Figure 70 Index of de-escalation of capital costs by technology**



Note: Indices reflect the mean rates of change in technology costs.

For the portion of installed costs due either to installation activity undertaken in Australia or equipment that is manufactured in Australia, learning-by-doing rates are applied which are tied to the level of installed capacity. The generic assumption is that these costs reduce 20% for every doubling of capacity.

Policy options can affect the rate of cost decline by affecting the level of capacity installed.

Power factors for capital costs de-escalation for each technology and learning by doing rates are based on a review of published estimates of capital cost movements and projected capital cost declines. Mean rates of decline in capital costs are sourced from:

- REN21 (2011), *Renewables Global Status Report: 2011*, New York

- R. Wiser et. al (2011), *Tracking the Sun II: The Installed Cost of Photovoltaics in the U.S. from 1998-2008*, Lawrence Berkeley National Laboratory.
- European Photovoltaic Industry Association (2011), *Solar Generation 6: Solar Photovoltaic Electricity Empowering the World*, Brussels.
- International Energy Agency (2011), *Projected Costs of Electricity Generation: 2010 Update*, Paris
- IHS CERA (2011), *Power Capital Costs Index*, Cambridge.

The power factor derived from this data show higher rates of decline for capital costs for new or just commercialised technologies. This reflects mainly the low level of capacity installed at an international level.

Capital costs are also affected by metal prices. Metal material costs represent around 25% to 30% of the final capital cost. Projections of metal prices (aluminium, copper and steel) are sourced from a range of sources[21], with the mean projection from these sources assumed.

A.4.3.1 Transmission costs

Transmission costs varied depending on the distance of the connection, the degree of any deep network upgrades and the voltage level required. Connection costs ranged from $110/kW to $500/kW.

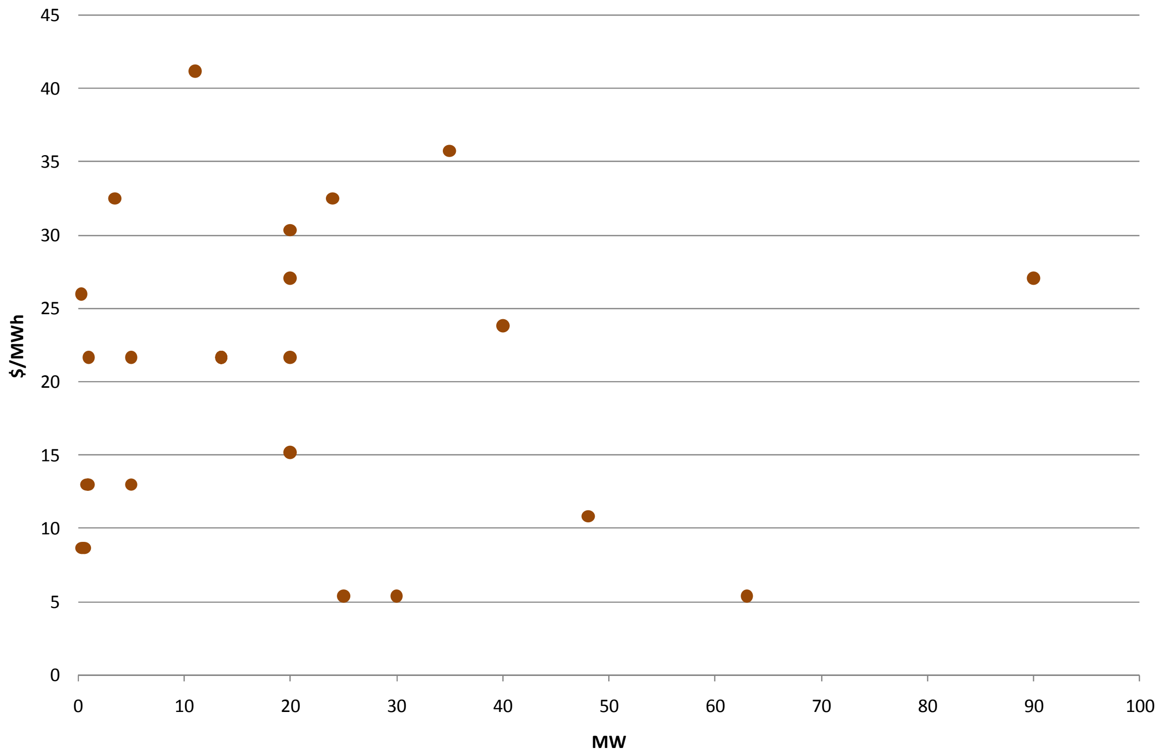
A.4.3.2 Fuel costs

Biomass projects incurred a fuel cost. Estimates of fuel cost ranged from $5/MWh to around $40/MWh (see Figure 71). The low end of the range of costs reflected the fuel cost for on-site generation using waste products (bagasse, landfill gas, sawmill or pulp mill waste). The mid to high range cost reflected projects utilising waste products with a transport component (e.g. municipal solid waste) the high end also reflected products with an opportunity cost (energy crops).

---

21 Sources include ABARE, BREE, World Bank

▪ **Figure 71 Fuel cost assumptions, biomass**



A.4.2.4 Operating and maintenance costs

Operating and maintenance costs assumptions are:

- For biomass projects, O&M costs ranged from $5/MWh to $25/MWh.
- For wind projects, O&M costs ranged from $8/MWh to $12/MWh.
- For hydro-electric projects, O&M costs were assumed to be $5/MWh
- For solar PV projects, O&M costs were assumed to $3/MWh
- For solar thermal projects, O&M costs were assumed to average $15/MWh

Wind projects in NSW and Victoria incurred an additional operating cost to cover the cost of obtaining approvals from landholders within the 2 km zones around turbines. The cost was calculated to be 75% of the cost paid per turbine (assumed to be $15,000 per annum) to landholders with turbines. The average additional cost is $4/MWh.

Wind projects also incurred an ancillary service cost to cover for services for voltage control and for intra-dispatch interval variations in generation. Ancillary costs start at $6/kW/yr for modest penetration of wind turbines in each State and were ramped up to $30/kW/yr when penetration of wind turbines reaches high levels (above 20% of peak demand).

Ancillary costs are not applied to other large-scale technologies as the level of intermittency is not as acute or the level of uptake is not likely to be as high.

A.4.4 LRMC curves

The expected long run marginal cost (at the regional reference node) is calculated as equal to the levelised cost for the assumed capacity factor for each generation project. The long run marginal cost for each generation option is calculated by the following formula:

$$LRMCti = (Cti + \Sigma i{=}I\ (Oti/(1+r)i))/(\Sigma i{=}I\ (Gi/(1+r)i))$$

Where *LRMCti* is the long run marginal cost in $/MWh for technology *t* in year *i*, *Cti* is the overnight capital cost for each technology *t* in year *i*, *Oti* is the annual operating costs over the life of the plant, *r* is the weighted average cost of capital and *G* is the generation level in each year. Capital costs include the capital expenditure on generation, transmission connection costs and interest during construction. Operating costs cover fuel costs, operating and maintenance costs, payments to landholders and the cost of ancillary services (if required). Generation levels are discounted by the assumed marginal loss factor for each generation options. The long run marginal costs are calculated over the economic life of the technology.

The weighted cost of capital was calculated based on assumptions on:

- An assumed debt to equity ratio set currently at 60%.
- Return on debt of 6.3% in real pre-tax terms (calculated from a nominal rate of 9% with an assumed inflation rate of 2.5%).
- Return to equity of 17% in real pre-tax terms.

Based on these assumptions the weighted average cost of capital was calculated to be around 11% in real pre-tax terms. A premium of 1 percentage point was added for biomass projects to account for fuel price risk. A premium of 3 percentage points was applied to novel technologies (with no demonstrated track record) or a first of a kind plant. This premium reduces to zero should the technology have a demonstrated performance for 10 years. The technologies covered include geothermal, solar thermal and ocean technologies. The premium applies only to the portion of investment not subsidised under government grant or loan programs.

Economic lives of the renewable energy technologies were assumed to be: 17 years for biomass projects; 25 years for hydro-electric (mini-hydro), geothermal and wind projects; 15 years for wave projects; 20 years for solar PV projects; and 30 years for solar thermal projects.

The long run marginal costs vary by region reflecting either variations on transmission costs and/or variations in resource quality (e.g. poorer wind regimes, differences in solar insolation and biomass fuel costs).

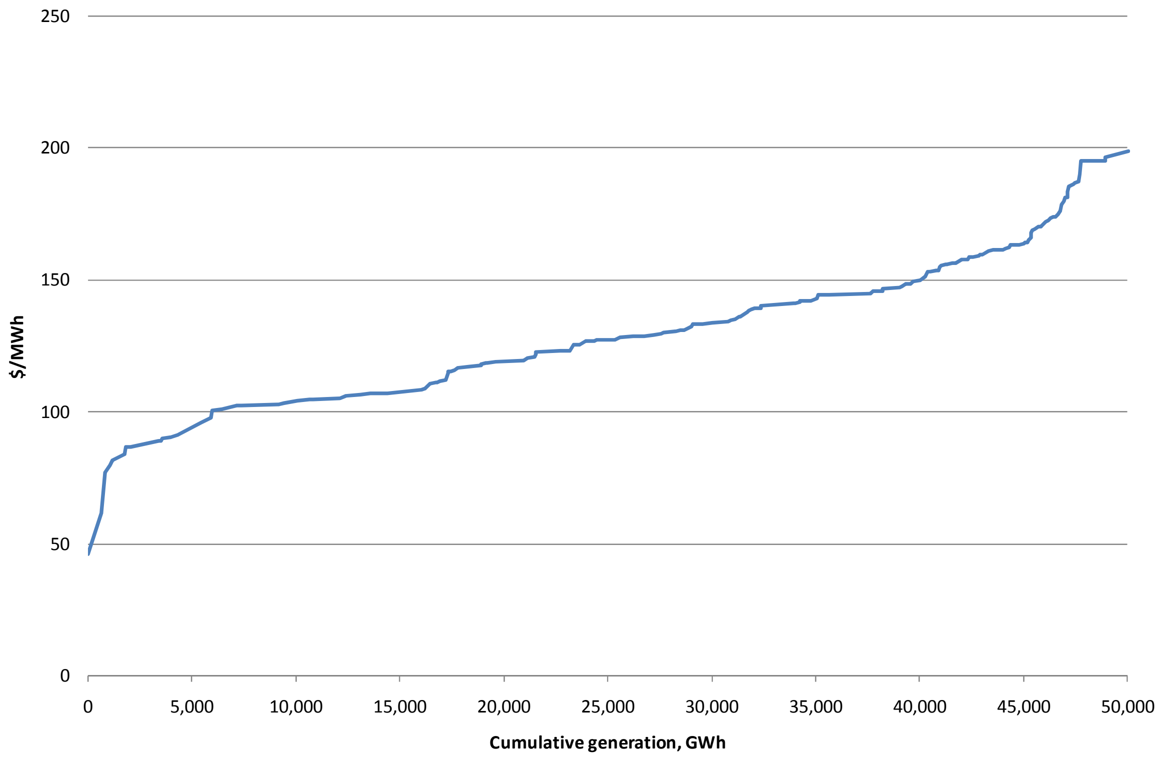
Assumptions on the cost of renewable generation are shown in Table 18. The long run marginal cost curves for available renewable energy in Australia are shown in Figure 72. The long run marginal cost in 2012 ranges from around $50/MWh (typically for upgrades that expands output) to around $280/MWh. Most projects have LRMCs in the range of $100/MWh to $150/MWh. An additional 30,000 GWh is required to meet the expanded LRET target, the long run marginal cost for which is around $135/MWh.

▪ **Table 18 Net long-run marginal costs of renewable generation options in 2012, $/MWh**

Renewable Generation Type	Minimum	Maximum, 95 percentile
Hydro-electric	50	150
Wind	85	180
Biomass	80	210
Solar/PV	155	280

Note: Long-run average costs represent average cost (including capital, transmission, operating and fuel costs) calculated using 11% pre-tax cost of capital. Solar/PV covers solar thermal, concentrating solar PV as well as flat plate PV projects. Costs are in mid 2012 dollar terms.

▪ **Figure 72 Long-run marginal cost curves for prospective renewable generation in 2012, mid 2012 dollar terms**



The long run marginal costs are expected to fall over time as capital costs decrease.

A.5 Electricity Market Model - NEM

Electricity market trends are essentially 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. Another major influence on prices is the uncertainty with regard to carbon prices and the remaining political risk around the implementation of the Carbon Pricing Mechanism (CPM). Consequently, assumptions on the fuel costs, unit efficiencies, and capital costs of new plant and carbon prices will have a noticeable impact on the long-term average price forecasts. 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.

A.5.1 Factors Considered

The market price forecasts take into account the following parameters:

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

In addition, the prices developed in this study reflect the carbon price expected to arise from the CPM policy. The study was conducted with the electricity demand forecasts as reflected in the median growth forecasts published by AEMO in June 2012[22].

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

A.5.2 Strategist Software platform

The wholesale market price forecasts were developed utilising SKM MMA's electricity market model having regard to the renewable and abatement markets for the Gas Electricity Certificates (GEC) in Queensland, the NSW Greenhouse Abatement Certificates (NGAC), and the Large-scale Generation Certificates (LGC)[23]. This model is based on the Strategist probabilistic market modelling software, licensed from ABB-Ventyx. Strategist represents the major thermal, hydro and pumped storage resources as well as the interconnections between the NEM regions. In addition, SKM MMA partitions Queensland into three zones to better model the impact of transmission constraints and the trends in marginal losses and generation patterns change in Queensland. These constraints and marginal losses are projected into the future based on past trends.

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

- All the dynamics of bid gaming over the possible range of peak load variation and supply conditions are not fully represented.

22 AEMO (2012), *National Electricity Forecasting Report for the National Electricity Market*, June, Melbourne
23 Note that the GEC and NGAC schemes no longer have any influence on wholesale markets while carbon pricing is effective

- Extreme peak demands and the associated gaming opportunities are not fully weighted. These uncertainties are highly skewed and provide the potential for very high price outcomes with quite low probability under unusual demand and network conditions.
- Marginal prices between regions are averaged for the purposes of estimating inter-regional trading resulting in a tendency to under-estimate the dispatch of some intermediate and base load plants in exporting regions such as Gladstone Power Station (GPS) in Central Queensland and Hazelwood in Victoria.

However, overall corrections can be made where these measures are important and in any case the error in modelling is comparable to the uncertainty arising from other variable market factors such as contract position and medium term bidding strategies of portfolios such as Energy Australia and AGL. Overall the forecasts produced using Strategist under the key assumptions presented in this report represent a conservative view, applicable for long-term investment in generation capacity[24]. Specific supply/demand scenarios can be provided to quantify unusual market conditions.

A.5.3 Strategist Methodology

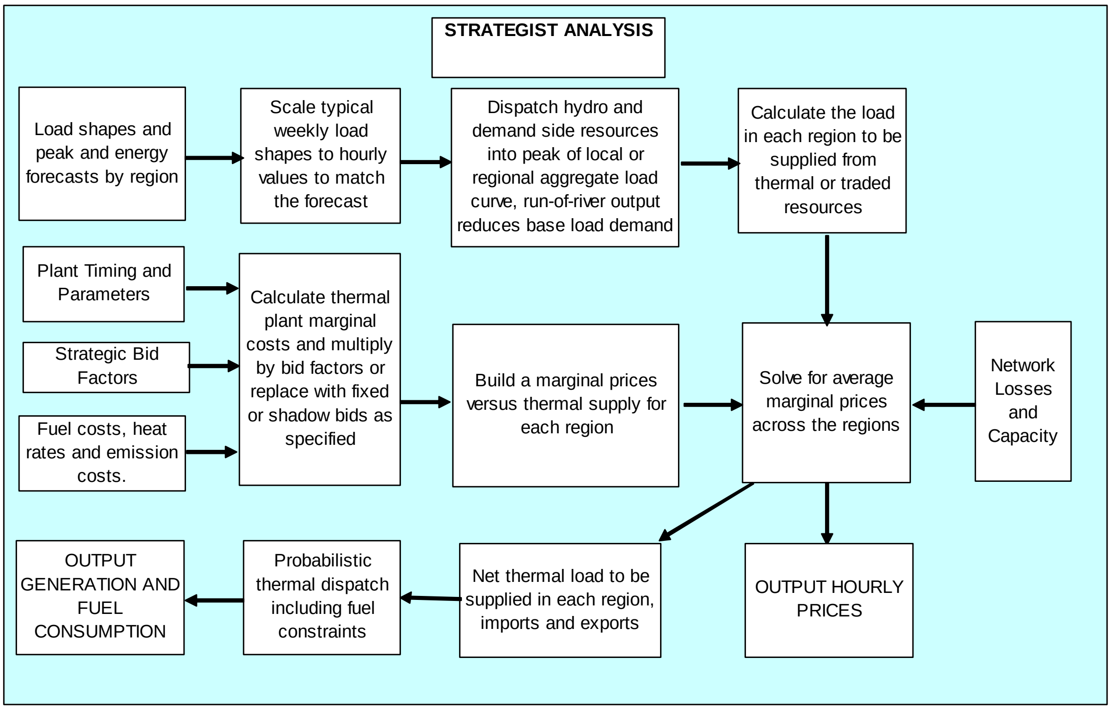
Average hourly pool prices are determined within Strategist based on thermal plant bids derived from marginal costs or entered directly. The internal Strategist methodology is represented in Figure 73 and the MMA modelling procedures for determining the timing of new generation and transmission resources, and bid gaming factors are presented in Figure 74.

We have used the PROVIEW module of Strategist to develop the expansion plan with a view to minimising the 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:

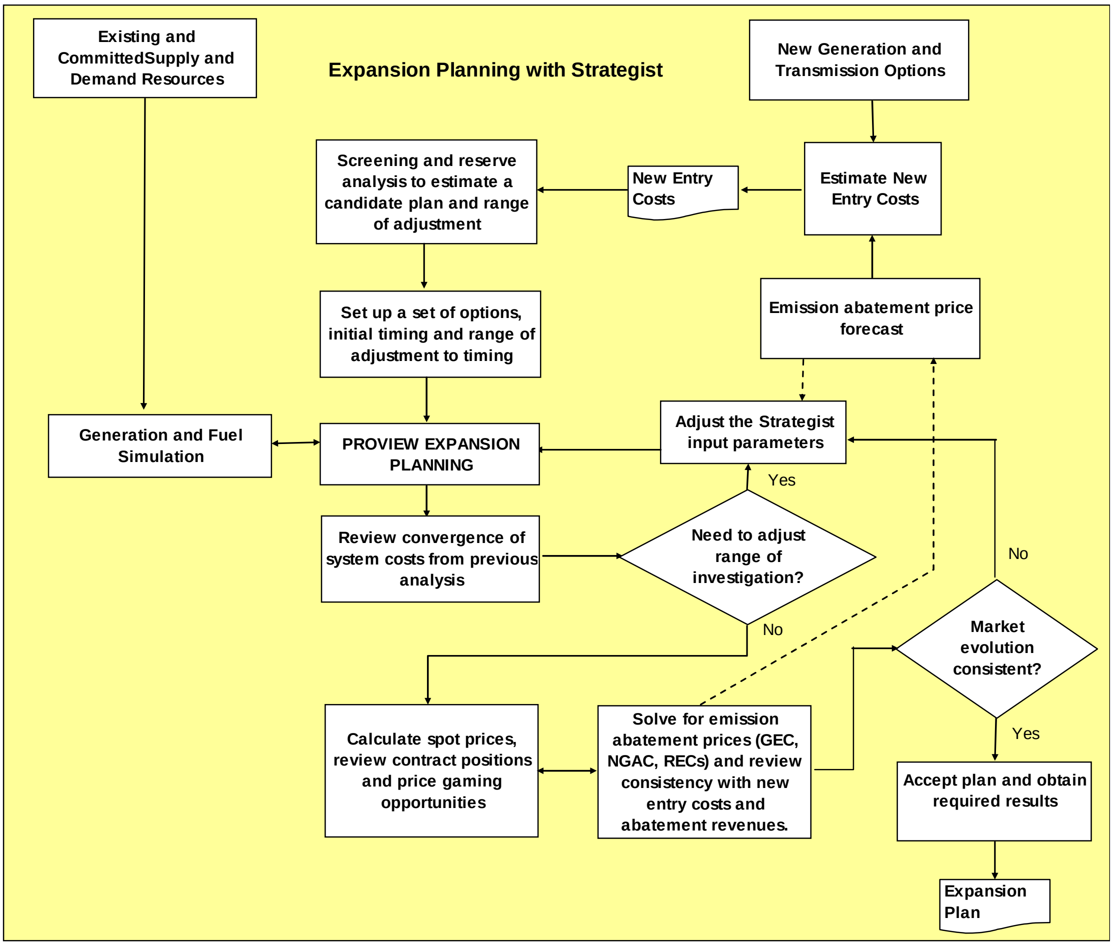
- The establishment of an optimal expansion plan (multiplicity of options and development sequences means that run time is the main limitation)
- The consistency of that plan with the GEC and NGAC (requires iteration within Strategist to estimate the GEC price and with external Excel spreadsheets to estimate the NGAC price if applicable).
- A review of the contract positions and the opportunity for gaming the spot market prices.

24 As at 30 September 2012, 43% of all NEM price forecasts prepared by SKM MMA since 1999 have been exceeded in present value terms at 9% real discount rate.

▪ Figure 73 Strategist Analysis Flowchart



▪ Figure 74 MMA Strategist Modelling Procedures



We therefore conduct a number of iterations of PROVIEW to develop a workable expansion plan and then refine the expansion plan to achieve a sustainable price path, i.e. able to support the revenue requirements of new entrants, applying market power where it is apparent and to obtain a consistent set of emission abatement prices and new entry plant mix.

Strategist generates average hourly marginal prices for each hour of a typical week for each month of the year at each of the regional reference nodes, having regard to thermal plant failure states and their probabilities. The prices are solved across the regions of the NEM having regard to inter-regional loss functions and capacity constraints. Failure of transmission links is not represented although capacity reductions are included based on historical chronological patterns. Constraints can be varied hourly if required and such a method is used to represent variations in the capacity of the Heywood interconnection, between Victoria and South Australia, which have been observed in the past when it was heavily loaded. Such variations in interconnection capacity occur during the threat of thunderstorms in proximity to the interconnecting transmission line to enhance system security, and during transmission line outages.

Bids are generally formulated as multiples of marginal cost and are varied above unity ratio to represent the impact of contract positions and the price support provided by dominant market participants. Some capacity of cogeneration plants is bid below short run marginal cost to represent the value of the steam supply which is not included in the power plant model. The modelling of Smithfield allows for the typical peak and off-peak dispatch levels having regard to the cogeneration requirements.

A.5.4 Assumptions

The pool price model is structured to produce hourly price forecasts for twelve typical weeks representing the month of each year. There are a large number of uncertainties that make projections of future pool prices difficult.

The scenario allows for medium energy growth as well as median peak demands, as provided in AEMO's 2012 National Electricity Forecasts. The demand forecast has been amended to take account of differences in assumptions related to carbon prices in formulating the forecast.

Other features of the assumptions include:

- Capacity is installed to meet the target reserve margin for the NEM in each region. Some of this peaking capacity may represent demand side response rather than physical generation assets.
- The medium demand growth projections with annual demand shapes consistent with the relative growth in summer and winter peak demand. The load shape was based on 2010/11 load profile for the NEM regions.
- Generators behaving 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 Market Price Cap (MPC) or removed from the simulation to represent strategic bidding of these resources when demand is moderate or low. Torrens Island A capacity is an example when some plant is never required for median peak demand.
- Emissions abatement based on the policy announcement for a commencement in July 2012.
- Additional renewable energy is included for expected Greenpower and desalination purposes.

- It was assumed that the increase in the Queensland gas fired generation target to 15% by 2020 will be replaced by the CPM. The target is increased from 13% at 0.5% per year from 2010.
- The assessed demand side management (DSM) for emissions abatement or otherwise economic responses throughout the NEM is assumed to be included in the NEM demand forecast.
- Carbon capture and storage is not available until 2025/26. The long term modelling for the Federal Treasury revealed that the threat of (relatively) low cost carbon capture and storage in the face of high carbon prices made problematic the entry of conventional CCGT plant in the medium term as a transitional base load technology. CCGTs would therefore only be commissioned sparingly, and only if prices are high enough to support a relatively rapid recovery of their fixed costs.
- Generation from any nuclear process is not available in the study period.
- The development of the 400 MW Integrated Drying Gasification Combined Cycle (IDGCC) plant by HRL in the Latrobe Valley has been shrouded in uncertainty due to a lack of investors. This project, which has a four year construction lead time, still seeks financial support and has recently been frozen by HRL because of a legal ruling that it cannot be built until an existing brown coal-fired power station has been shut down. Given the delays and uncertainty surrounding the project, it was not considered in this study.
- The retirement of the 2 x 300 MW Munmorah units at the end of September 2014.
- The retirement of the Swanbank B units, as planned by CS Energy in 2011 and 2012.
- The early retirement of Snuggery unit 3 is no longer expected. We have closed the three gas turbines by June 2020.
- Playford is retired in June 2012. It is possible for Playford to run longer as it has a high emission rate and may be required to be available to receive free permits. However, it is not considered critical to supply reliability except in extreme hot summer conditions.

A.5.5 Demand forecast and embedded generation

The demand forecast adopted by SKM MMA on AEMO's latest median forecast of electricity demand which are outlined in Section A.1[25]. The forecast was applied to the 2011/12 actual half-hourly demand profiles and is shown Table 9 for each region for medium growth for the median growth forecast. The forecasts indicate relatively flat load growth in the period to 2018 in most regions with the exception of Queensland. The lower growth rate reflects the impact of consumers' reaction to higher retail electricity prices, slower world economic growth rates and the impact of restructuring of the manufacturing sector.

We have used the 2010/11 load shape as it reflects demand response to normal weather conditions and captures the observed demand coincidence between States. SKM MMA adjusts the AEMO forecasts to add back in the "buy-back" component of the renewable embedded generation including small scale embedded generation from roof-top solar PV systems. SKM MMA's Strategist model is then used in conjunction with a renewable energy model to explicitly project renewable energy. Some embedded generation, such as small scale cogeneration is not included in the Strategist model, and the native load forecasts are adjusted accordingly.

The use of the 50% POE peak demand is intended to represent typical peak demand conditions and thereby provide an approximate basis for median price levels and generation dispatch.

---

25 AEMO (2012), National Electricity Forecasting Report for the National Electricity Market, June, Melbourne

The peak is applied as an hourly load in Strategist rather than half-hourly as it occurs in the market. Because the Strategist model applies this load for one hour in a typical week it is applied for 4.3 hours per year and therefore it represents a slightly higher peak demand than the pure half-hour 50% POE. This compensates to some degree for not explicitly representing the variation up to 10% POE.

The introduction of the CPM adds yet another complexity to the demand forecasting as it is anticipated that there will be some demand response to the predicted increase in electricity prices. The published forecasts already include assumptions on how demand may change in response to these higher electricity prices. AEMO reported the long-run own price elasticity of electricity demand (PED) by region used to derive this anticipated demand response (see Table 19). This PED represents the percentage change in demand expected for a 1% increase in electricity price. The elasticity for New South Wales and Victoria are generally higher due to more energy intensive loads such as smelters. The new median demand forecast assumes the Kurri Kurri smelter is closed, but no other smelter is affected over the forecast period.

With respect to peak demand, we assumed the demand response would be significantly lower and therefore the corresponding change in peak demand was assumed to be only 25% that of the energy reduction. This method allows for the observation that air-conditioning load which dominates the summer peak is not very price sensitive.

The demand profile does not assume any storage and battery uptake for inter-temporal load management.

- **Table 19 Assumed price elasticity of demand across all loads**

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

Note: This is the average elasticity over all the loads. Source: AEMO (2009).

A.5.6 Supply

A.5.6.1 Marginal costs

The marginal costs of thermal generators consist of the variable costs of fuel supply including fuel transport plus the variable component of operations and maintenance costs. The indicative variable costs for various types of existing thermal plants are shown in Table 20. We also include the net present value of changes in future capital expenditure that would be driven by fuel consumption for open cut mines that are owned by the generator. This applies to coal in Victoria and South Australia.

Table 20 Indicative average variable costs for existing thermal plant in 2012 ($June 2012)

Technology	Variable Cost $/MWh	Technology	Variable Cost $/MWh
Brown Coal – Victoria	$3 - $10	Brown Coal – SA	$24 - $31
Gas – Victoria	$46- $64	Black Coal – NSW	$20 - $23
Gas – SA	$37 - $111	Black Coal - Qld	$9- $31
Oil – SA	$250 - $315	Gas - Queensland	$25 - $56
Gas Peak – SA	$100- $164	Oil – Queensland	$241- $287

A.5.6.2 Fuel costs

Gas and coal prices are discussed in Section 3.5 and the specific prices input into Strategist are presented in A.5.

A.5.6.3 Plant performance and production costs

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

A.5.7 Market structure

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

- Victorian generators are not further aggregated and there is no change to ownership structure apart from the recent purchase by AGL of 100% of Loy Yang A.
- NSW generators remain under the current portfolio structure.
- The generators' ownership structure in Queensland remains as public ownership.
- The SA assets continue under the current portfolio groupings.

A.5.8 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[26] for operational reasons or bid at its 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. This strategy maximises profit in the short-term, excluding any long-term flow on effects into the contract market.

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

[26] "Self-committed" means that the generator specifies the timing and level of dispatch with a zero bid price. If generators wish to limit off-loading below the self-commitment level, a negative bid price down to -$1,000/MWh may be offered. This may result in a negative pool price for generators and customers.

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.

A.5.9 Future market developments

A.5.9.1 Committed and planned entry

The recently developing power projects and reserve plant are shown in more detail in Table 21. 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 2010 ESOO. It also shows other projects for which, according to the 2010 ESOO, planning is well advanced. Table 21 demonstrates that new entry being investigated with a substantial number of new projects in the pipeline. The table does not include renewable energy generation projects.

A.5.9.2 Interconnections

Assumptions on interconnect limits are shown in Table 22 and their current operating levels are illustrated in Figure 75. The export limit from South Australia to Victoria on the Heywood Interconnection has since been increased to 460 MW under favourable conditions. The Victorian export limit to Snowy/NSW is sometimes up to 1300 MW. 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.

- **Table 21 Mothballed and reserve capacity and recently developed new plants in the NEM**

Power Plant	Generated Capacity (MW)	Region	Service Date	Status
Munmorah	2 X 300	NSW	Reserve	Both 300 MW units are operable at short notice when other units are unavailable. Retired at the end of September 2013.
Buronga OCGT (IP)	150	NSW	To be advised	Publicly announced
Dalton (AGL)	4 * 290	NSW	October 2013	Publicly announced
Eraring upgrade	4 x 60	NSW	Dec 11 – May 13	Committed in 2010 ESOO by 2012/13
Wellington GT 1-4 (ERM Power)	640	NSW	October 2013	Publicly announced
Leaf's Gully (AGL)	2 * 180	NSW	To be advised	Advanced
Bamarang OCGT (Delta)	300	NSW	2014	Publicly announced
Bamarang CCGT	400	NSW	2014	Publicly announced
Marulan OCGT	350	NSW	2014	Publicly announced
Marulan CCGT	450	NSW	2014	Publicly announced
Mt Piper Coal	2 * 1000	NSW	2014 - 2016	Publicly announced
Munmorah Rehabilitation	2 * 350	NSW	2014	Publicly announced
Parkes OCGT (IP)	150	NSW	To be advised	Publicly announced
Tallawarra B CCGT	450	NSW	To be advised	Publicly announced
Tomago OCGT	To be advised	NSW	To be advised	Publicly announced

Power Plant	Generated Capacity (MW)	Region	Service Date	Status
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
HRL IDGCC	300	VIC	2016	Publicly announced. Excluded from modelling

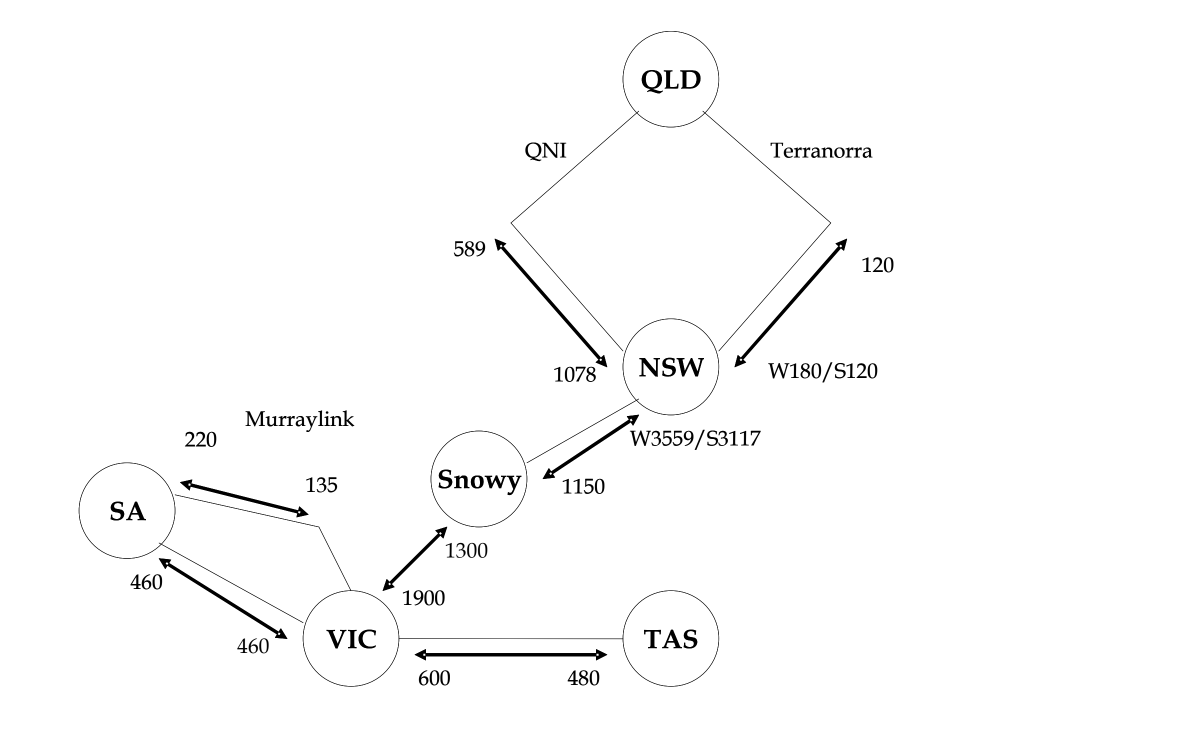
For example, in the case of the transfer limit from NSW to Queensland via QNI and Terranora, the capability depends on the Liddell to Armidale network, the demand in Northern NSW, the output from Millmerran, Kogan Creek and Braemar, and the limit to flow into Tarong[27].

- **Table 22 Interconnection limits – based on maximum recorded flows since 2005/06**

From	To	Capacity	Summer
Victoria	Tasmania	480 MW	
Tasmania	Victoria	600 MW	
Victoria	South Australia	460 MW	
South Australia	Victoria	460 MW	
South Australia	Redcliffs	135 MW	
Redcliffs	South Australia	220 MW	
Victoria	Snowy	1,300 MW	
Snowy	Victoria	1,900 MW	
Snowy	NSW	3, 559 MW	3,117 MW
NSW	Snowy	1,150 MW	
NSW	South Queensland	120 MW	
South Queensland	NSW	180 MW	120 MW
NSW	Tarong	589 MW	
Tarong	NSW	1,078 MW	

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

- **Figure 75 Representation of interconnectors and their limits**



We have retained a Snowy zone in our Strategist model to represent the impact of constraints either side of the Victoria/NSW border.

Basslink has a continuous capacity of 480 MW and a short-term rating up to 600 MW. Prior to the CPM, 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 CPM 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 CPM as having 480 MW continuous capacity in each direction.

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

- An upgrade of the QNI export limit by an additional 400 MW in both directions by series compensation on the Armidale-Dumaresq-Bulli Creek 330 kV circuits, upgrading the Armidale to Tamworth line, implementation of the System Protection Scheme for the Terranora Interconnector and the addition of a third Molendinar transformer.
- An upgrade of the existing Victoria to South Australia export limit from 460 MW to 630 MW by adding a third transformer at the Heywood Terminal Station and adding a line from Heywood to South East to Tungkillo. This also requires the segregation of the Eastern Hills network from the rest of the meshed network and also increasing Victorian export capability by a further 150 MW to 200 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. This option has been further developed in the latest NSW Planning Statement to include options with augmentation of 180 MW (augmentation reference numbers 12 and 11 in the 2006 SOO) and then up to 2,500 MW total transfer capacity from Snowy to Victoria.

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.5.10 Bidding and new entry

SKM 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 2010 ESOO and 2011 ESOO and are summarised in Table 23.

The minimum reserve level for VIC and SA combined is adjusted for reserve sharing to minimise the local reserve requirement in SA. This means that Victoria must carry 530 MW when South Australia is partially relying on Victoria. The increase in reserve in Queensland reflects both the increase in the size of the largest unit by 300 MW (Kogan Creek) and the support provided to NSW through increased export power flows.

- **Table 23 Minimum reserve levels assumed for each state**

	Qld	NSW	Vic	SA	Tas
Reserve Level 2006/07	480 MW	-1,490 MW	665 MW	-50 MW	144 MW
Reserve Level 2007/08 – 2009/10	560 MW	-1,430 MW	665 MW	-50 MW	144 MW
Reserve Level 2010/11	829 MW	-1,548 MW	653 MW	-131 MW	144 MW
Reserve Level 2011/12	913 MW	-1,564 MW	530 MW	-268 MW	144 MW
Reserve Level 2012/13 onward	913 MW	-1,564 MW	176 MW *	-116 MW *	144 MW

* Adjusted to allow for reserve sharing between the regions

After selecting new entry to meet AEMO's minimum reserve criteria, SKM 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. SKM MMA does not believe that new brown coal without carbon capture and storage capability is ready to be the price setter for new entry in Victoria until after 2024/25, and even then only with high gas prices.

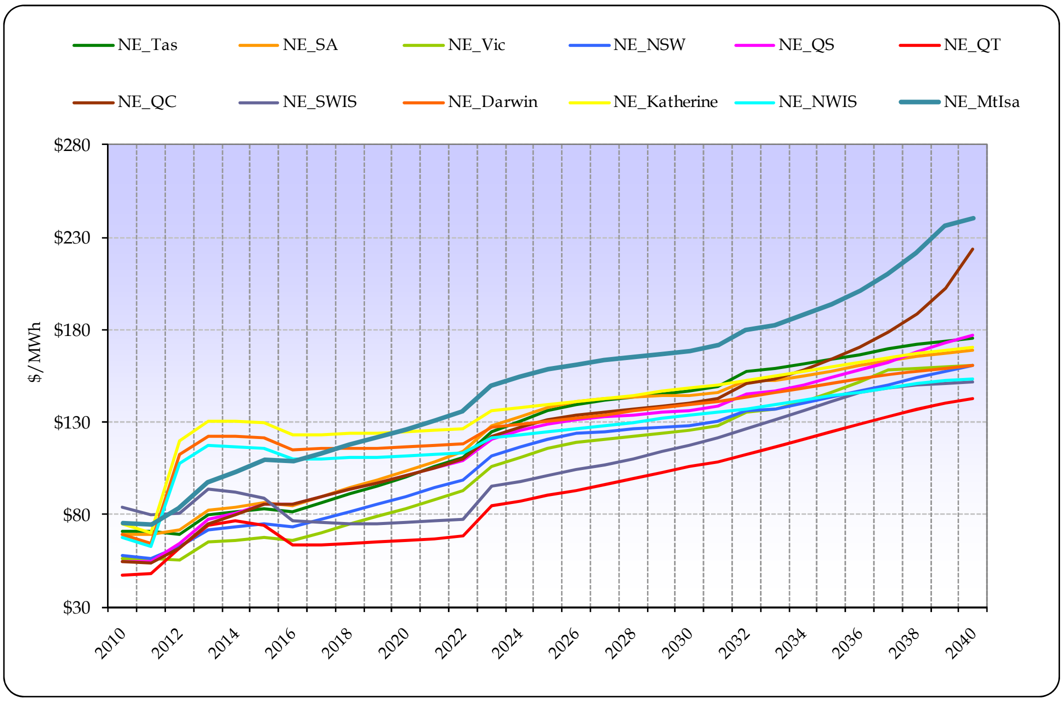
- Infrequently used peaking resources are bid near MPC or removed from the simulation to represent strategic bidding of such resources.

The base (with carbon pricing) scenario new entry prices with scheme commencement in July 2012 are shown in Figure 76 in June 2012 dollars for the various electricity regions. These new entry prices include the impact of emission abatement schemes such as Gas Electricity Certificates (GECs) in Queensland and the NSW Gas Abatement Certificates (NGACs) prior to July 2012. The new entry cost for Tasmania is based upon the lower of the cost of imported power through new transmission capacity from the mainland on a new link or a new combined cycle gas fired plant in Tasmania. As gas price rises, the cost of imported power becomes cheaper than local CCGT generation, particularly as lower emission generation becomes available on the mainland.

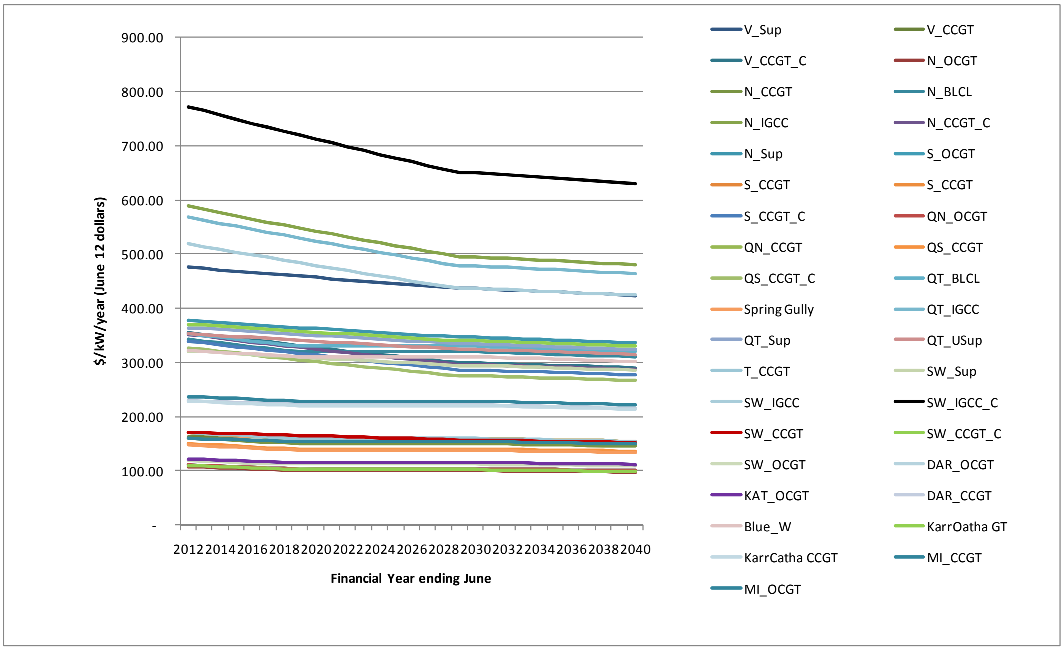
In general, the new entry prices increase as a result of:

- Rising real costs of coal and, particularly, natural gas, which indicate a sharp increase in real terms over the next 5 years and then a gradual real price increase of around 1% to 2% per annum over the long term.
- Rising carbon prices which are assumed to rise around 4.5% in real terms.
- But slightly offset by small decline in capital costs of new plant.

Figure 76 New entry prices with carbon pricing from July 2012 for Scenario S1 (June 2012 $/MWh)



▪ **Figure 77 Trend in New Entry Capital Recovery Costs ($/kW/year June 2012 dollars)**



Cost and financing assumptions used to develop the long-term new entry prices are provided in Table 14 applicable to the financial year 2014/15 in June 2012 dollars. The trend in annualised capital recovery costs is shown in Figure 77 for a range of thermal power options through Australia. The lowest cost fixed costs are attributable to the open cycle gas turbines, the lower middle range to combined cycle gas turbines, and the higher costs to options with carbon capture and storage. The real pre-tax real 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 WACC of 10.60 % pa. It is assumed that the higher risks emerging in the electricity generation sector from CPM will require these higher equity returns.

The capacity factors in Table 24 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.

- **Table 24 New entry cost and financial assumptions ($ June 2012) for 2014/15**

	Type of Plant	Capital Cost, $/kW	Available Capacity Factor	Fuel Cost , $/GJ*	Weighted Cost of Capital, %	LRMC $/MWh (d)	+ Core Policy CO_2, $/MWh
SA	CCGT (a)	$1,466	92%	$6.40	10.60%	$65.47	$78.80
Vic	CCGT (a)	$1,353	92%	$5.72	10.60%	$64.02	$77.20
NSW	CCGT (c)	$1,373	92%	$6.23	10.60%	$68.70	$81.99
NSW	Black Coal (b)	$2,383	92%	$1.74	10.60%	$54.83	$76.81
Qld	CCGT (c)	$1,462	92%	$5.97	10.60%	$69.26	$85.03
Qld	Black Coal (Tarong) (b)	$2,497	92%	$0.78	10.60%	$50.95	$72.34
Qld	Black Coal (Central) (b)	$2,494	92%	$1.43	10.60%	$59.58	$82.14

Note: fuel cost shown as indicative only. Gas prices vary according to the city gate prices. (a) extension to existing site; (b) not regarded as a viable option due to carbon emission risk; (c) at a green field site; (d) excluding abatement costs or revenues

These capacity factors do not necessarily reflect the levels of duty that we would expect from the units. They represent the plant availability and therefore are relevant for estimating time weighted prices. The unit's true LRMC measured in $/MWh on average output 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 a significantly different price path.

The process of developing a least cost expansion plan is the method to properly estimate the entry of intermediate generation, rather than relying on new entry cost curves alone.

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 generator marginal losses losses applied are those published in the AEMO 7 July 2011 Report "List of Regional Boundaries and Marginal Loss Factors for the 2011/12 Financial Year". We have not yet been able to process the later values published in 2012.

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

Intra-regional losses are applied as detailed in the AEMO 7 July 2011 Report V3.1 "List of Regional Boundaries and Marginal Loss Factors for the 2011/12 Financial Year".

The long-term trend of marginal loss factors is extrapolated for three more years and then held at that extrapolated value thereafter.

A.5.11 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. Table 25 and Table 26 show the monthly energy used in our model for the smaller hydro schemes.

▪ **Table 25 Monthly energy for small hydro generators modelled in Strategist, GWh**

Month	Barron	Hume (Vic)	Kareeya
January	15.93	7.62	26.83
February	30.92	8.60	13.45
March	20.80	9.27	21.48
April	18.74	8.41	20.59
May	11.80	6.04	36.35
June	15.93	0.00	47.36
July	11.80	0.00	26.24
August	17.05	0.00	32.78
September	13.49	6.04	28.91
October	19.11	10.84	28.62
November	4.87	9.91	28.32
December	6.93	8.54	26.54
Total	187.38	75.26	337.46

Based on our market information we have produced monthly and annual monthly energy values for the Snowy Hydro units. This information has been incorporated into the Strategist simulation as monthly energy generation. Daily release constraints cannot be modelled in Strategist.

The monthly minimum generation for Blowering and Guthega are based on market information acquired by SKM 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.

▪ **Table 26 Monthly energy for AGL hydro-electric units, GWh**

Month	Dartmouth	Eildon 1-2	Kiewa/ McKay
January	26.78	42.37	8.27
February	23.56	33.25	7.23
March	21.42	31.32	7.23
April	10.71	27.54	12.40
May	5.36	1.57	24.80
June	5.36	0.00	33.07
July	8.57	1.13	36.17
August	10.71	4.22	43.40
September	10.71	13.17	47.54
October	12.85	14.14	51.67
November	21.42	14.30	44.44
December	23.56	22.56	28.94
Total	181.00	205.57	345.16

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 2010 the Murray annual energy has been reduced to 1,795 GWh per annum. Table 27 shows the monthly generation for Murray, the Tumut power stations and for Hydro Tasmania. Hydro Tasmania's generation is set to the stated long-term average of 8700 GWh from 2011/12.

- **Table 27 Monthly energy limits for Snowy Hydro and Hydro Tasmania (GWh)**

Month	Murray	Upper Tumut	Lower Tumut	Hydro Tasmania
January	114.74	134.21	46.20	716.53
February	178.19	192.44	43.67	508.08
March	172.03	148.78	43.84	677.22
April	149.48	121.72	45.78	708.18
May	166.52	164.12	51.16	783.00
June	195.22	196.68	39.57	957.00
July	238.83	261.92	44.58	783.01
August	207.94	153.79	47.54	696.00
September	42.00	8.84	47.69	870.00
October	125.00	10.00	43.60	835.53
November	91.60	115.64	46.88	568.80
December	114.39	121.64	44.50	596.67
Total	1795.93	1629.79	545.00	8700

A.6 Electricity Model – Western Electricity Market

Forecasts for electricity prices are discussed in this section. The forecasts are based on a simulation of the Western Australian Electricity (WEM) market based on SKM MMA's dispatch model and the general assumptions listed below. The methodology is similar to the methodology deployed for the NEM.

In this section, the key assumptions underpinning SKM MMA's market model of the WEM are outlined.

A.6.1 Trading arrangements

The wholesale market for electricity in the WEM 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 WEM 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 the WEM, 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 System Management (Western Power). System Management 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 SKM MMA's WEM 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 115MW with the largest cost disproportionately allocated to the largest unit.

In the SKM MMA model of the WEM, 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.

A.6.2 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.

A.6.3 Demand assumptions

Three key demand parameters are used in the model:

- Peak demand at bus bar.
- Energy requirements.
- Load profiles.

IMO's median case energy sent out forecasts for the WEM 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 SKM MMA's projections for electricity sent out. The annual compound growth rate for total electricity demand in the WEM is around 3.0%.

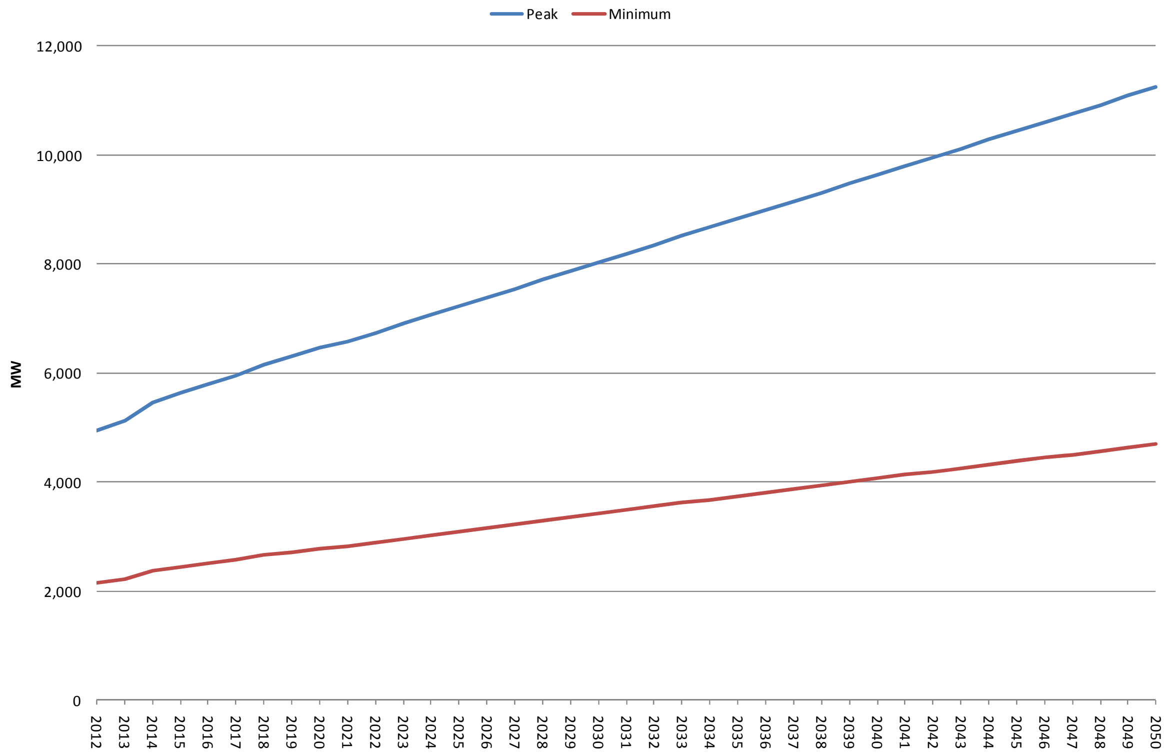
Projections of the summer and winter peak demand at generator bus bar are derived from forecasts of sent out peak demand provided by the IMO.

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

Using data provided by IMO, SKM 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.

Peak and minimum (or base load) demand forecasts are shown in Figure 78. The peak is forecast to grow from just under 5,000 MW in 2011/12 to around 11,300 MW in 2049/50. The minimum or base load portion of demand (around 2,100 MW in 2011/12) is projected to double in the forecast period. The base load portion is around 43% of the peak demand.

- **Figure 78 Peak and minimum (base load) demand forecasts – median scenario**



A.6.4 Generation assumptions – existing units

Verve Energy

Verve Energy has 11 power stations operating in the SWIS, as shown in Table 28. The Muja stations operate as base load stations with capacity factors of 70% to 95%. The Kwinana steam plants and the Mungarra gas turbines operate as intermediate plants with capacity factors of about 40%, while the Pinjar gas turbines operate as peaking plant with 2% to 10% 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 30MW 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 130MW 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 2016.

The physical characteristics and the fixed and variable operating and maintenance costs for each plant are shown in the following tables.

Table 28 Power plant operating assumptions

Station	Type	Capacity in summer peak, MW sent out	Fuel	Maintenance (%)	Forced outage (%)	Heat rate[2] GJ/MWh
Albany	Wind turbine	12 x 1.8	renewable	-	3	-
Collie A	Steam	304	coal	6	2	10.0
Muja A/B	Steam	4 x 60	coal	6	6	13.0
Muja C	Steam	2 x 185.5	coal	4	4	11.0
Muja D	Steam	2 x 200	coal	4	3	10.5
Kwinana C	Steam	2 x 180.5	coal, gas	4	6	10.8
Kwinana GT	Gas turbine	16	gas, dist	2	3	15.5
Pinjar A,B	Gas turbine	6 x 29	gas	6	3	13.5
Pinjar C	Gas turbine	2 x 91.5	gas	6	3	12.5
Pinjar D	Gas turbine	123	gas	6	3	12.5
Mungarra	Gas turbine	3 x 29	gas	6	3	13.5
Geraldton	Gas turbine	16	gas, dist	2	3	15.5
Kalgoorlie	Gas turbine	48	dist	2	3	14.5
Cockburn	CCGT	2*120	gas	4	2	7.5
Kwinana LMS100	Gas	2*100	gas	3	3	10.8
Worsley[1]	Cogeneration	70	gas	4	2	8.0
Tiwest	Cogeneration	29	gas	6	3	9.0

1 South West Cogeneration Venture – 120MW nameplate, 50% Western Power owned.
2 Heat rates at maximum capacity. Heat rates are on a sent out basis (that is, GJ of energy delivered per unit of electricity sent-out in MWh). Heat rates are on a higher heating value basis.
Source: Verve Energy, Annual Report, 2010-11, Perth (and previous issues); estimates of maintenance time, unforeseen outages and heat rates for OCGTs and CCGTs are based on information supplied by General Electric and the IEA.

Table 29 Fixed and variable operating costs

Station	Unit	Fixed costs ($000s/year)	Variable costs ($/MWh)
Albany	0	0	
Collie	A	10,000	4.00
Muja	C	10,500	5.50
	D	11,000	5.00
Kwinana	C	16,000	7.00
	GT	1,000	9.00
Pinjar	A,B	1,000	4.00
	C	3,000	4.50
	D	3,000	4.50
Mungarra		1,000	4.00
Geraldton		500	5.00
Kalgoorlie		500	5.00
Wellington		0	5.00
Worsley		3,000	4.00
Tiwest		1,000	4.00

Source: Derived by SKM MMA to match operating and maintenance cost data contained in Verve Energy's Annual Reports.

A.6.5 Other generators

Private generating capacity, including major cogeneration, is detailed in Table 30. The capacity is mostly comprised of gas-fired generation. There has been a large increase in privately-run generating capacity due to substantial falls in gas costs and the gradual deregulation of the generation sector. Over the 1996-97 period, some 324 MW of privately-owned generation capacity was commissioned, at Kwinana and the Goldfields.

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

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

- **Table 30 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
ERM	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
Collgar Wind Farm	wind	206	2.0	2.0	-
Western Energy	gas	120	2.0	2.0	10.5

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

Most of the plants are located near major industrial loads. 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.

A.6.6 New thermal units

To meet the anticipated growth in demand in the SWIS beyond 2012, additional generation plants will be required. Furthermore, Verve Energy has committed to retiring old and inefficient units – for example, Kwinana C.

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.

Table 31 Assumptions for new thermal generation options

Option	Life Years	Sent-out Capacity MW	Capital Cost, 2010 $/kW so	Heat Rate at Maximum Capacity GJ/MWh	Variable O&M Cost $/MWh	Fixed O&M Cost $/kW
Black coal						
Subcritical coal	35	184	1,879	9.6	3	30
IGCC	30	187	2,673	9.1	2	44
IGCC with CC	30	180	3,688	11.4	3	50
Natural gas						
CCGT	30	235	1,467	7.4	3	22
Cogeneration	30	235	1,740	5.0	3	20
CCGT with CC	30	216	2,201	8.6	4	44
OCGT with CC	30	135	742	11.0	4	29

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

The wind farms at Walkaway and Emu Downs are assumed to continue to operate past 2030, with a capacity factor of around 35%. Collgar also operates past 2030 at a capacity factor of 40%. 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 LGC market or from the emissions trading market.

A.6.6.1 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. Fuel costs for the WA system are defined in Table 31.

A.7 Generation Capacity of Mt Isa, NWIS and DKIS

The following table summarises the existing generation capacity in Mt Isa, the NWIS and the DKIS.

Region and Power Station	Operator	Capacity (MW)	Fuel
Mt Isa			
XStrata	XStrata	30	Natural gas
Mica Creek	CS Energy	325 (10x30-35)	Natural gas
Total[28]		445	
NWIS			
Dampier	Rio Tinto	120	Natural gas
Cape Lambert	Rio Tinto	105	Natural gas
Paraburdoo	Rio Tinto	2x40 aero-derived gas turbine 20 old industrial turbine	Natural gas
Port Hedland	Alinta	90	Natural gas
Newman	Alinta	105	Natural gas
Total		520	
DKIS			
Channel Island	PWC	232	Natural gas or liquid fuel
Weddell	PWC	86	Natural gas or liquid fuel
Berrimah	PWC	30	Natural gas or liquid fuel
Katherine	PWC	21	Natural gas or liquid fuel
Pine Creek	NGD(NT) Cosmo Power	35	Natural gas or liquid fuel
Total[29]		494	

A.8 Renewable Energy Models

A.8.1 REMMA

The Australian renewable energy market may be modelled in REMMA, SKM-MMA's renewable energy model. REMMA is a tool that estimates a least cost renewable energy expansion plan, and solves the supply and demand for LGCs having regard to the underlying energy value of the production for each type of resource (base load, wind, solar, biomass with seasonality). REMMA is an Excel application based on a database of nearly 900 existing, committed, proposed and generic projects across Australia.

---

28 Includes additional 90 MW from onsite diesel or gas fired plants at more remote mines.
29 Includes additional 90 MW from smaller regions of Alice Springs and Tennant Creek.

It is generally common practice to run Strategist in tandem with the renewable energy market model to determine that the wholesale market solution is also compatible and most efficient with regard to renewable energy markets. Additional renewable generation has the effect of reducing wholesale prices while reduced wholesale prices typically have the effect of reducing investment in renewable generation. Iteration of these models in tandem typically allows the overall solution to converge to a stable model of consistent wholesale and renewable energy markets.

The REMMA model allows SKM-MMA to model the impact of policies affecting the expanded RET scheme, should such form part of the subset of policies considered for further review. Policies affecting the RET scheme are often compatible with other carbon abatement policies as they can affect change to LGC prices and technology uptake over the period of the scheme and therefore have considerable influence on emissions abatement.

Projecting LGC prices with the REMMA model is based on the assumption that the price of the LGC will be the difference between the cost of the marginal renewable generator and the price of electricity achieved for that generation. The basic premise behind the method is that the LGC provides the subsidy, in addition to the electricity price, that is required to make the last installed (marginal) renewable energy generator to meet the LGC target economic without further subsidisation. The REMMA uses a linear programming algorithm to determine least cost uptake of renewable technologies to meet the target, subject to constraints in resource availability and regulatory limits on uptake. The optimisation requires that the interim targets are met in each year (by current generation and banked certificates) and generation covers the total number of certificates required over the period to 2030 when the program is scheduled to terminate. The certificate price path is set by the net cost of the marginal generators, which enable the above conditions to be met and result in positive returns to the investments in each of the projects. SKM-MMA has a detailed database of renewable energy projects (existing, committed and proposed) that supports our modelling of the LGC price path. The database includes estimation of capital costs, likely reductions in capital costs over time, operating and fuel costs, connection costs, and other variable costs for over 900 individual projects.

The price of certificates may be affected by:

- Regulations affecting supply, which will impact on the level and cost of each renewable generation technology. The Act defines eligible sources of renewable generation and defines restrictions on fuel sources, such as waste wood derived from native forests and plantations. Only renewable resources currently eligible are modelled.
- Other regulations that impact on the availability of resources, such as environmental and heritage regulations which may affect the amount of renewable generation occurring in some locations. The restrictions include: a ban on generation options close to urban areas, restricting the level of wind generation by location due to setback arrangements (such as those recently proclaimed in Victoria) and restrictions on availability of fuels for biomass projects.
- The underlying cost of renewable energy technologies, including the cost of any network upgrade required to supply the grid and ancillary services. Network upgrade costs are included in the modelling where information is available. An assumption is also made for a cost impost on

intermittent generation alternatives (primarily wind generation) for an additional cost for the provision of ancillary services[30]. This is assumed to be about $10 to $30/kW/year.

- Prices received for renewable energy generation in wholesale electricity markets. Prices received are affected by a number of factors, including the reliability of generation and the location of the generator. So for example, wind farm generation in South Australia receives a discount of 15% on the expected price received.
- Revenue earned from other potential services provided by renewable generation, such as the ancillary services, avoidance of network costs, and avoidance of waste disposal costs. In the modelling, revenue from other sources is assumed to be zero.

Because of banking, current prices in the LGCs market will be based on the expectations of future market conditions of all traders involved. Thus, the current price will be an expected price based on a number of possible future market scenarios and the probability of these scenarios eventuating. Other short-term factors may also impact on the price.

In our modelling, we attempt to project certificate prices for a most likely outcome in terms of electricity price, availability of renewable resources and generation costs. Therefore, we have not explicitly modelled the impact of short-term or other factors that may affect expected prices.

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

Data on the level of variability of renewable options are sparse. The two most affected technologies are wind and hydro-electric generation. Preliminary data on wind generation indicates a year on year variability of plus or minus 10 per cent (95% confidence interval). Variability in annual hydro generation is about plus or minus 11 per cent based on data from the Snowy Mountain Scheme and Hydro Tasmania.

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

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

---

30 Because generation from a wind farm can vary from minute to minute, additional resources are required to stabilise voltage on associated network elements. See Arnott, I. (2002), "Intermittent Generation in the National Electricity Market", National Electricity Market Management Company, Melbourne.

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

Because many of the biomass fuels are by-products of other productive activities, their availability is subject to economic factors affecting those activities. For example, bagasse is a by-product of sugar cane production and the amount of sugar cane crushed. Supply of sugar cane is variable due to the variability of sugar prices on world markets and variable weather conditions (which can also affect fibre content). This is included as a premium on the discount rate of 1% to reflect this uncertainty.

The future costs of renewable projects also depends on the forecast reductions in capital prices resulting from technological improvements, the value of the relevant exchange rate and the ability of the project to obtain additional government support. In recent times, increases in labour and material costs have boosted the capital cost of both renewable and fossil fuel generation options.

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

A.8.2 DOGMMA

A.8.2.1 Method

Uptake of renewable technologies is be affected by a number of factors. DOGMMA (Distributed On-site Generation Market Model Australia) determines the uptake of renewable technologies based on net cost of generation (after FIT revenue and other subsidies are deducted from costs) versus net cost of grid delivered power. Because the cost of renewable generation will vary by location and load factors, the model estimates uptake based on renewable resources and load levels within distribution regions. Other factors that may impact on the decision are modelled as a premium prepared to be paid for small scale renewable generation. The premium is calculated based on market survey data and other published market data. The premium is also assumed to decrease as the rate of uptake increases (reflecting the fact that the willingness to pay will vary among customers).

The cost of small scale renewable energy technologies is treated as an annualised cost where the capital and installation cost of each component of a small scale generation system is annualised over the assumed lifespan of each component, discounted using an appropriate weighted average cost of capital. Revenues include sales of electricity using time weighted electricity prices on the wholesale and retail market (as affected by emission trading), avoidance of network costs including upgrade costs if these can be captured, and revenues from other Government programs such as the PV rebate programme and the expanded RET.

The model is:

- Disaggregated by the major transmission nodes for each state. The number of eligible residential and/or commercial entities in each region will be the basic unit for modelling. That is, costs of delivered electricity will be modelled for each entity or other customer group where these customer groups will be defined by insolation levels, renewable energy resource cost and load profiles. The degree of disaggregation within customer classes will depend on the amount of data available on insolation levels, renewable energy resource cost and load profiles.

- The degree to which each customer grouping will adopt renewable energy technologies will also depend on tariff arrangements, with assumptions made on the uptake of interval meters and the time of use tariffs.

The model has a built in function to reduce the cost of generation from small scale technologies as a function of adoption of these technologies. International studies have indicated that the level of utilisation is likely to be the best predictor of future cost reductions through learning by doing. Economies of scale in production are likely to be achieved through increasing capacity installed.

A.8.2.2 Assumptions

The following section presents our key modelling assumptions.

A number of constraints that limit the uptake of distributed generation are included in the model:

- Economic constraints. As the capacity of distributed generation in a region increases, the unit cost of generation also increases. This is modelled as reduced capacity factor for all small-scale technologies as more uptake occurs (in the case of wind, this reflects the fact that as more wind farms are built, they are likely to locate in less windy areas).
- Technical and regulatory constraints. A number of maximum capacity limits are imposed to mimic the impact of technical limits to uptake in a region or regulatory impediments. The maximum capacity limits can also be used to model the effect of social issues such as the amenity affect of wind generation in residential areas and some sensitive sites.
- Geographic constraints. The off-take nodes have been divided into metropolitan and rural nodes and have been utilised to assign the availability of potential capacity in a region for wind and hydro resources.
- General constraint. The capacity of distributed generation is not allowed to exceed the local peak demand (as this would entail the need to export power to other regions which would incur additional costs not modelled).

Forecasts of local demand at each node were derived by taking the actual peak demand for 2010/11, as published by state based transmission planners, and then applying the state-wide peak demand growth rate as forecast by the latest AEMO forecasts. The larger states were represented by multiple nodes, whereas South Australia and Tasmania were each treated as single node regions.

Energy consumption for each region was calculated from peak demand by using the state-wide load factor. A correction factor was applied to ensure that the sum of energy consumption at each node equalled state-wide energy consumption.

Assumed technical parameters for each of the distributed generation options are shown in Table 32. Although the model can handle variations in the assumptions by region, we assumed that the technical assumptions for each generation technology were the same in each region. However, the capacity factor for wind generation shown in the table represents the maximum capacity factor achievable in the region. The actual capacity factor decreases as the level of wind generation increases within a region.

It is assumed that in each region, the actual plant size will be equal to maximum allowed size except for the last plant chosen, which may have a lower capacity.

- **Table 32 Technical assumptions for distributed generation options**

Parameter	Rooftop PV	Small Wind	Small Hydro	Solar Water Heater	Heat Pump Water Heater
Annual uptake limit as maximum proportion of total demand, %	0.5	0.001	0.0001	0.1 – 0.3	0.1 – 0.3
Maximum plant size	0.001 – 0.01 MW	0.003 – 0.03 MW	0.001 MW	315 litres	315 litres
Capacity factor, %	15 - 18	16 - 38	30	20 - 23	20 - 23
Outage rates, % of year	1	3	3	3	3
Emission intensity of fuel, kt of CO2e/PJ	0.0	0.0	0.0	0.0	0.0

Note: PV capacity factors vary by region according to solar insolation levels. Wind capacity factor varies by the amount of wind generation in a region. Source: SKM MMA analysis.

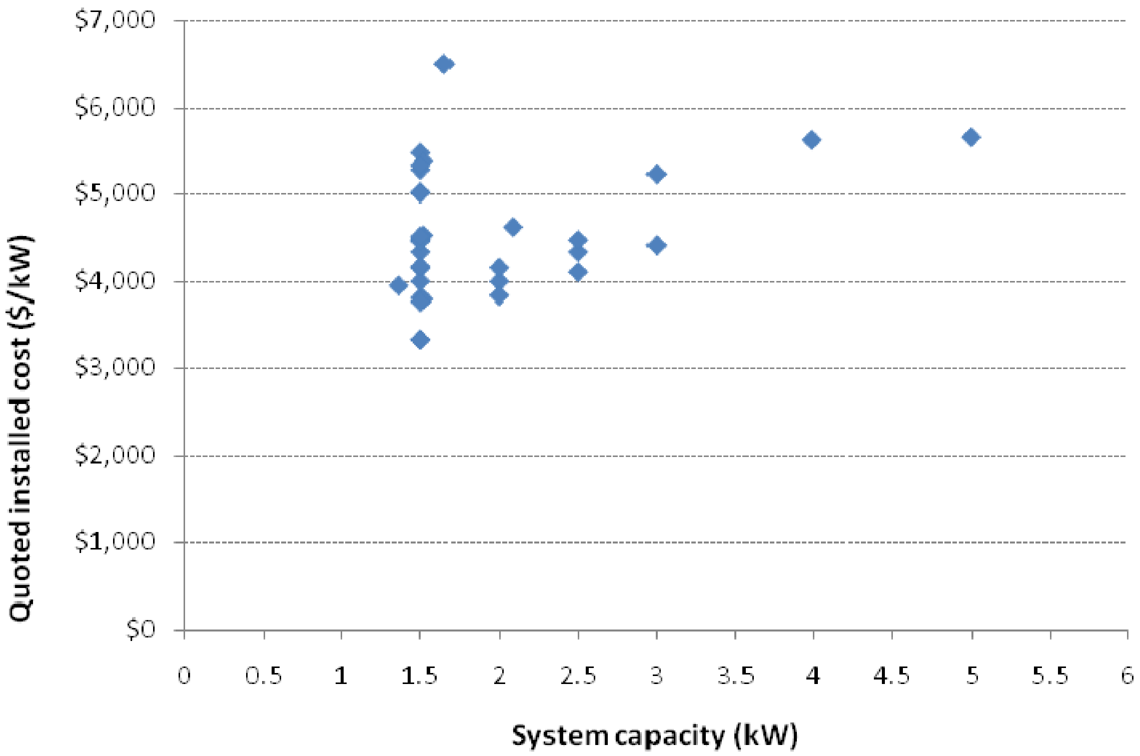
Unit capital costs are also assumed to decrease over time, reflecting long-term trends. Capital cost assumptions for 2012 are based on market research conducted by SKM MMA for a range of suppliers across Australia, and represents an average cost per kW including installation and before any Government rebates or credits. Wind capital costs are assumed to decline 2% per annum by 2020 and 1% per annum thereafter. Photovoltaic system capital costs are assumed to decline by 7% per annum until 2014

and then at 6%, mini hydro systems are assumed to decline at 1% per annum, whereas SWHs and HPWHs are assumed to be flat in real terms since they are more mature technologies.

Capital costs are annualised over the life of the plant, assumed to be 15 years for all plants. Costs are annualised using a real weighted average cost of capital set at 5% above the risk-free long-term bond rate (which, based on latest 10 year treasury bond rates, is about 2.1% per annum in real terms).

The average installed system cost for residential PV has dropped dramatically over the last 24 months and is now around $4,000 per kW in Australia for a typical roof top system. Figure 79 shows the results of some market research conducted by SKMA MMA, where the quoted installed costs for PV systems excluding subsidies have been plotted against system size. Smaller systems cost a little more and larger system a little less by achieving some economies of scale and bulk purchase of panels; however installation cost tends to be higher for the larger systems making the total installed cost per kW for larger systems greater than smaller ones.

▪ **Figure 79 Quoted installed cost for PV systems by system capacity, excluding subsidies**



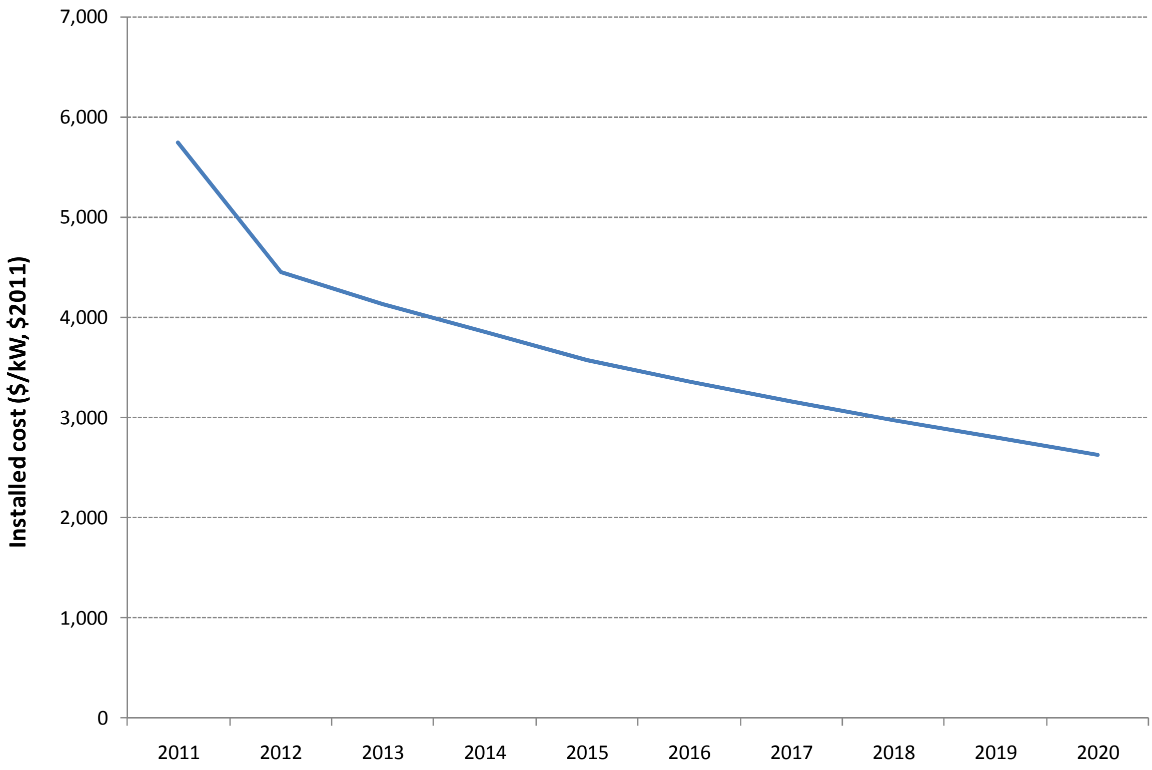
Predicting the future price of any product is difficult and subject to large uncertainties. The key parameters that will determine the future cost of PV cells include:

- Raw material cost.
- Other input costs.
- Economic conditions.
- Demand and production levels.
- Technology.

Many of these parameters are interlinked and improvement in one may force higher costs in another. For example, as costs fall due to increased economies of scale in manufacturing, upward cost pressure may result from the increased demand forcing up raw material costs. However, technology improvements may reduce the quantity of raw material required or the type of material necessary.

Data over the past 25 years have revealed that there has been a 20% cost reduction for every doubling of the cumulative production of PV cells. This linear behaviour of cost with cumulative volume is typical of most manufacturing, and is expected to continue at the historical rate of 20% for each doubling of cumulative production volume. Prices are projected by the EPIA to fall by 7 percent each year in real terms between 2010 and 2015 under their advanced scenario, which is essentially a continuation of current support measures. This also assumes that global demand continues to rise to encourage technology improvements and that manufacturing capacity can keep pace with this demand. SKM MMA's assumed installed cost for PV systems over the next ten years is shown in Figure 80.

- **Figure 80 Assumed installed cost for PV systems, 1 kW capacity**



Note: years are financial years ending in year shown.

Photovoltaic cell output is directly related to the intensity of the sunlight falling on the panel. The sunlight intensity or solar insolation varies with global position (effectively distance from the equator), and local climate, such as cloud cover. Across Australia the solar insolation varies significantly and the output of a given solar array is dependent on its location. To account for these variations we have estimated the PV system capacity factors at each of the transmission nodes employed in the analysis using the RET Screen PV Energy Model. The key inputs for this analysis are the geographic coordinates of the locations involved, the orientation, configuration, and tracking of the panel, and the monthly average temperature and solar radiation. The climate data are available from the NASA Surface Meteorology and Solar Energy Data Set. Calculated capacity factors are reduced by 2 percentage points to reflect a comparison of real world data (as obtained by IPART) with pre-calculated data.

The resulting system capacity factors range from 13% (Tasmanian location) to 17% (northern Australia).

Installed costs for solar water heaters and heat pumps were estimated by a survey of suppliers for the most popular products. It was found that the most popular residential systems had capacities in the order of 300 litres, with an average installed cost of about $4600 for solar water heaters and $4500 for heat pump water heaters, excluding rebates. Since these are mature technologies, it was assumed that projected installed costs would be flat in real terms.

SWHs and HPWHs do not actually generate electricity, but rather they displace either electricity or gas demand (depending on the system they've replaced) by heating water directly. The amount of energy displaced by these systems was estimated from the typical number of STCs such systems are entitled to claim, assuming a 15 year life. This ranged from 1.7 MWh per annum for solar water heaters in Tasmania to 2.0 MWh per annum for solar water heaters in the northern states. A similar range was also applicable to heat pump water heaters.

Distributed wind generation at a scale greater than 0.5 kW has reached a reasonable level of maturity in the market for off-grid power, and is now becoming available and installed in grid-connected applications.

Based on available systems in the 0.5 kW to 20 kW size range, and including all ancillary equipment and installation costs, a correlation between system size and cost has been developed. These costs are based on retail equipment prices and include GST but do not include any government rebates or incentives. Costs for grid-connected wind turbines have become relatively constant over a capacity range of 0.5 kW to 20 kW and are in the vicinity of $6,500/kW but may increase to around $15,000/kW for sub 0.5 kW units.

The capacity factor of a wind turbine is a function of the local wind regime and the generation characteristics of the turbine. As an example we have determined average annual wind speeds at each of the regional locations utilised in the modelling of the Victorian nodes using the interactive wind map on the Sustainability Victoria website. For other states, we have used data provided by Government authorities or prorated to available wind generation capacity factors.

The capacity factors for wind turbines have been adjusted for the fact that they operate at lower altitudes than were measured for the wind maps and available wind farm data. Most wind turbine manufacturers publish the wind speed to power output relationships of their turbines, and these allow the average wind speed to be transformed into an annual energy output that allows the capacity factors to be calculated in each region. We have based the wind-to-energy conversion on the data for a 1.8 kW grid connected turbine manufactured by Southwest Wind Power, but have reduced the outputs by 20% to account for the lower output one would expect in locations that are likely to be less than the ideal. Capacity factors are assumed to range from 15% to 25% throughout Australia.

Note that the capacity factor estimates for each state represents maximum estimates for each region. As small scale wind generation capacity increases, the capacity factors decrease.

Appendix B Modelling changes

A number of changes have been made to the SKM MMA output data and report in this release, incorporating stakeholder feedback and model refinements. Details of the main changes are:

1) Increases to the SHW uptake assumed. SHW uptake is now based on assumptions provided by CCA as detailed in Section 3.8 of the report.
2) Adjustments to the Solar Credit multiplier, with the multiplier now set to one from 1st January 2013, consistent with recent announcements from Greg Combet.
3) Coverage of a broader range of resource costs spanning all States and Territories, resulting in an increase in the total resource cost reported for all scenarios.
4) Refinements to the modelling to better align the levels of renewable generation assumed between models, resulting in an increase in the domestic emission abatement levels attributed to LRET and a reduction in resource costs in the low demand scenario.

The key results reported in the previous and revised versions of the report are summarised in the following tables. The new figures continue to support the conclusions provided in the original report.

Previous summary of results released with Discussion Paper (October 2012)

Case	NPV change in Resource cost ($M)	Change in Emissions (Mt)	Average change in RET certificate cost to 2031 ($/MWh)	Average Wholesale price change# ($/MWh)	Average Retail Price change# ($/MWh)	Average change in Annual Bill ($)	NPV of Household bill Change ($)^
Updated 20% target	-4,360	94	-3.3	2.3	-0.6	-4	-7
No RET	-7,759	215	-9.7	6.7	-2.1	-15	-170
Combined LRET and SRES	-2,070	54	-0.7	1.0	0.5	4	70
Reference Case 2	263	-12	-1.6	7.6	7.0	49	600
Zero Carbon Price	1,419	157	1.4	-26.8	-28.9	-202	-1580
Low Demand	-12,539	-297	1.5	-13.2	-13.8	-97	-790

Revised summary of results (November 2012)

Case	NPV change in Resource cost ($M)	Change in Emissions (Mt)	Average change in RET certificate cost to 2031 ($/MWh)	Average Wholesale price change# ($/MWh)	Average Retail Price change# ($/MWh)	Average change in Annual Bill ($)	NPV of Household bill Change ($)^
Updated 20% target	-4,457	119	-3.9	3.4	0.1	0.4	9
No RET	-8,645	217	-9.7	6.7	-2.1	-15	-154
Combined LRET and SRES	-2,390	68	-1.1	1.7	0.9	6	70
Reference Case 2	437	-12	-1.9	7.9	7.1	50	595
Zero Carbon Price	2,035	137	1.5	-27.7	-29.7	-208	-1,611
Low Demand	-5,938	-349	1.7	-13.7	-14.4	-101	-827

For more information please contact:

AUSTRALIA Michael Connarty or Nicola Falcon

T: +61 3 8668 3051 E: mconnarty@globalskm.com or nfalcon@globalskm.com

www.skmconsulting.com

Asia, Australia, Europe, Middle East, New Zealand, South America

achieve outstanding client success

SINCLAIR KNIGHT MERZ

SKM