Benefit of the Renewable Energy Target to Australia's Energy Markets and Economy

Report to the Clean Energy Council

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SKM

Contents

Executive Summary

A target mandating the purchase of new renewable energy generation by retailers has been in operation in Australia since 2001. The Renewable Energy Target (RET) scheme is being reviewed by the Climate Change Authority this year. To inform this review, the Clean Energy Council engaged SKM MMA to undertake an analysis to:

1. Review the outcomes of the RET to date
2. Project the future impact of the RET
3. Understand the implications of stopping the RET

The electricity markets across Australia were modelled with and without the RET as well as other sensitivities, and past and future impacts were investigated. Impacts on investment in renewable energy and fossil fuel generation, wholesale and retail electricity prices and emissions abatement were examined in this study. There were also no reliability or security of supply issues identified in the analysis undertaken. The outcomes presented in this report are focussed on the RET impacts. Other complementary measures such as Green Power, feed-in-tariffs and the carbon price have, and are expected to continue to have an impact on the renewable energy industry.

Key Findings

The modelling shows that:

Between 2001 and 2012:

- The RET has delivered $18.5 billion of investment in renewable energy infrastructure
- Wholesale energy prices are as much as $10/MWh lower as a result of the RET being in place
- Emissions are 22.5 Mt CO_2e lower as a result of the RET. Without the RET Australia would not have met its emission reduction target under Kyoto

Between 2012 and 2030:

- By itself the RET is expected to deliver an additional $18.7 billion of investment in renewable energy infrastructure.
- Wholesale energy prices are expected to be up to $9/MWh lower with the RET in place
- 1000 MW less gas fired generation capacity is expected to be required with the RET in place
- Generation from gas-fired power stations is expected to be 13% less with the RET in place
- Generation from coal-fired power stations is expected to be 12% less with the RET in place

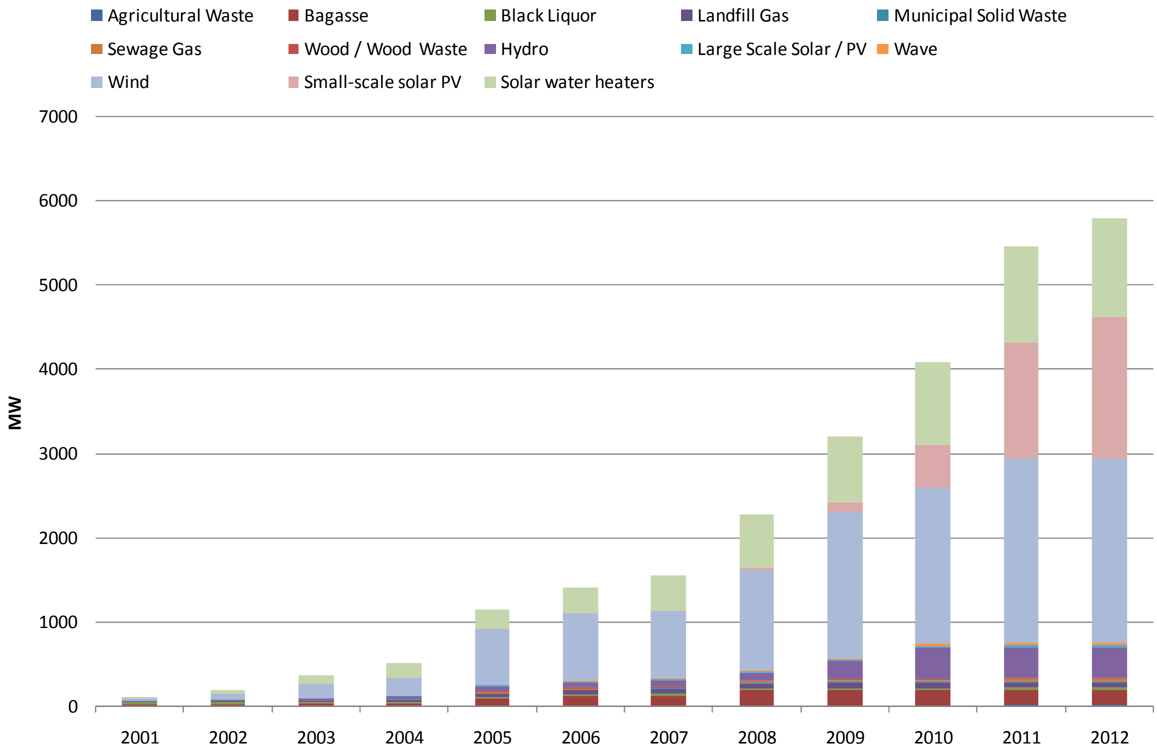
Renewable Energy Target– Historical Perspective

Renewable energy generation in Australia has been supported by a range of measures to assist in research and development of new technologies and deployment of newly commercialised technologies. The main support measure driving deployment is the Renewable Energy Target (RET) Scheme.

The RET has driven the deployment of renewable energy capacity, increasing from around 7,540 MW in 2000 to around 13,340 MW in 2012. This comprised of an increase in 2,945 MW in large-

scale projects, and 2,855 MW of small-scale PV and solar water heaters. This represents an increase since 2001 at an average annual rate of around 480 MW per annum.

- **Figure 1: Renewable capacity installed since 2001**



Uptake has predominantly been in wind generation, which accounted for approximately 38% of capacity installed since 2000, followed by small scale solar water heaters and small-scale PV systems which accounted for approximately 20% and 29%, respectively. Biomass capacity comprised approximately 6% and new hydro electric capacity (mainly from upgrades at existing systems) also comprised approximately 6% of installed capacity.

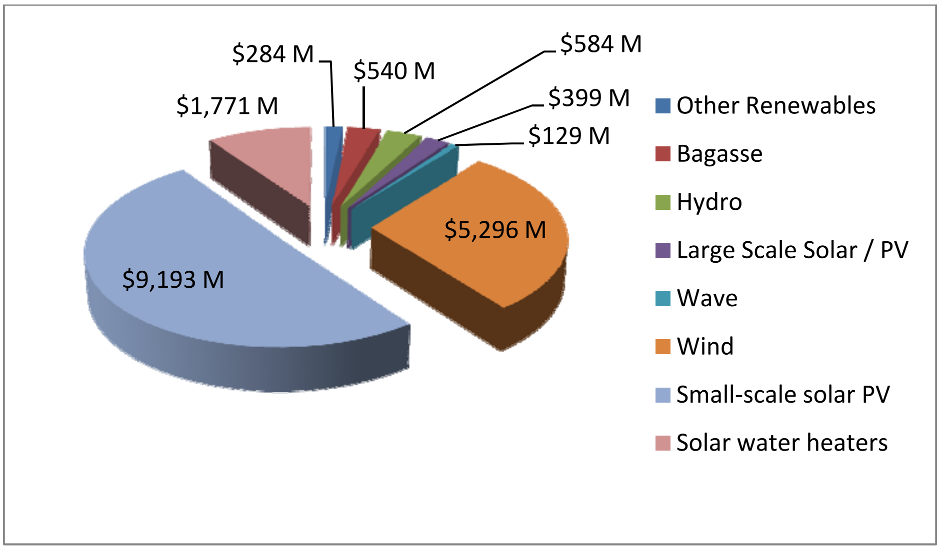
Wind generation, being lower cost, has been the dominant large scale technology under the RET with nearly 2,200 MW of wind farms developed. This significant deployment has resulted in technological developments including:

- An increase in average wind farm size from less than 15 MW before the RET commencement to around 100 MW on average in 2010. This trend is likely to continue in the near future with the commissioning of wind farms with capacities greater than 200 MW.
- An increase in the turbine size from around 1.5 MW to around 2 MW to 3 MW.
- Improvement in availability and capacity factors.

Investment in renewable energy technologies

Investment in renewable generation has amounted to approximately $18.5 billion, with $7.5 billion in large scale systems and $11.0 billion in small-scale systems. Note, these figures represent only fully operational generation with another $3.7 billion under construction.

- **Figure 2 Investment in new renewable generation since 2001**



The trends seen since 2001 are expected to continue, with wind expected to dominate investment in large scale systems. Despite the winding back of payments under feed-in tariff arrangements and under the Small-scale Renewable Energy Scheme (SRES), uptake in small scale systems is expected to continue at a steady pace.

Impact on electricity markets

Analysis shows that to date the RET scheme has had an impact on wholesale prices in most regions. Without the RET, most regions would have experienced higher wholesale energy prices than have been experienced with the RET. This is most evident in South Australia where a greater proportion of renewable energy has been deployed. Modelling indicates that an average reduction in wholesale prices of $4/MWh, with a maximum price reduction exceeding $10/MWh, could have occurred on the wholesale market in South Australia as a result of the RET scheme.

Retail prices have decreased slightly as a result of the RET with the average change since inception estimated to be -$0.63/MWh to -$4.41/MWh. The costs of purchasing certificates have averaged around $0.06/MWh in 2001 to $3.13/MWh in 2012. These costs partly outweigh the decreases in wholesale price, but overall a slight reduction in prices has occurred.

It is difficult to isolate a single driver for the reduction in wholesale prices with it likely to be attributable to a combination of factors. These could include:

- Reducing electricity demand - The uptake of solar water heaters and small scale roof top PV systems contributes to the reduction in electricity demand by displacing the need for grid based electricity.
- Reduced gas demand - to the extent that large scale renewable energy generation has reduced gas-fired generation (typically the last plant dispatched in the system). Uptake of solar water heaters may have also reduced the demand for gas for residential use.
- Spreading the location of generation to a greater range of regions, in some cases improving the efficiency of use of transmission systems and reducing system losses.

Over 1000 MW of new roof-top systems have been installed since the beginning of 2011, and the impact of this generation has not yet been felt in full, on actual demand. Given the impact of PV on reducing electricity demand, it can be expected that continued deployment of PV will continue to have an impact on future electricity demand.

The RET has already had an impact on delaying investment in fossil fuel generation. Around 500 MW of open cycle gas turbine generation has been deferred by around 2 to 3 years.

Analysis of spot price data also showed that over the last year volatility has subsided significantly. The current period in the NEM is unprecedented with respect to spot price volatility in that all five regions are experiencing volatility levels that are at or close to record lows. The only historical occurrence of volatility that simultaneously extended across regions was in early 2002, when low demand resulting from a very mild summer affected spot prices in both Victoria and South Australia. This suggests that the current drivers of the low volatility, namely low demand growth and increased penetration of renewable energy, are having far reaching effects that are extending across the entire NEM.

Other impacts

The RET scheme has a range of impacts on industry as well. Although there have only been some manufacturing activities directly attributable to the scheme, other service activities have been stimulated increasing employment in those activities. Development of these activities may have led to the development of new export industries. Furthermore, income earnt from wind farms has stabilised the financial prospects of farm enterprises[1].

Other economic benefits may have been created especially in the context of a carbon constrained world. These benefits include the development of new capabilities in deploying low emission technologies and gradual cost reductions through learning by doing and economies of scale in production. Although many components that make up renewable energy generation are imported, there is still significant scope for cost reductions in the assembly, distribution, erection and financing of renewable energy generation. These benefits will eventually lead to lower costs (than would have occurred otherwise) in meeting future carbon emission caps.

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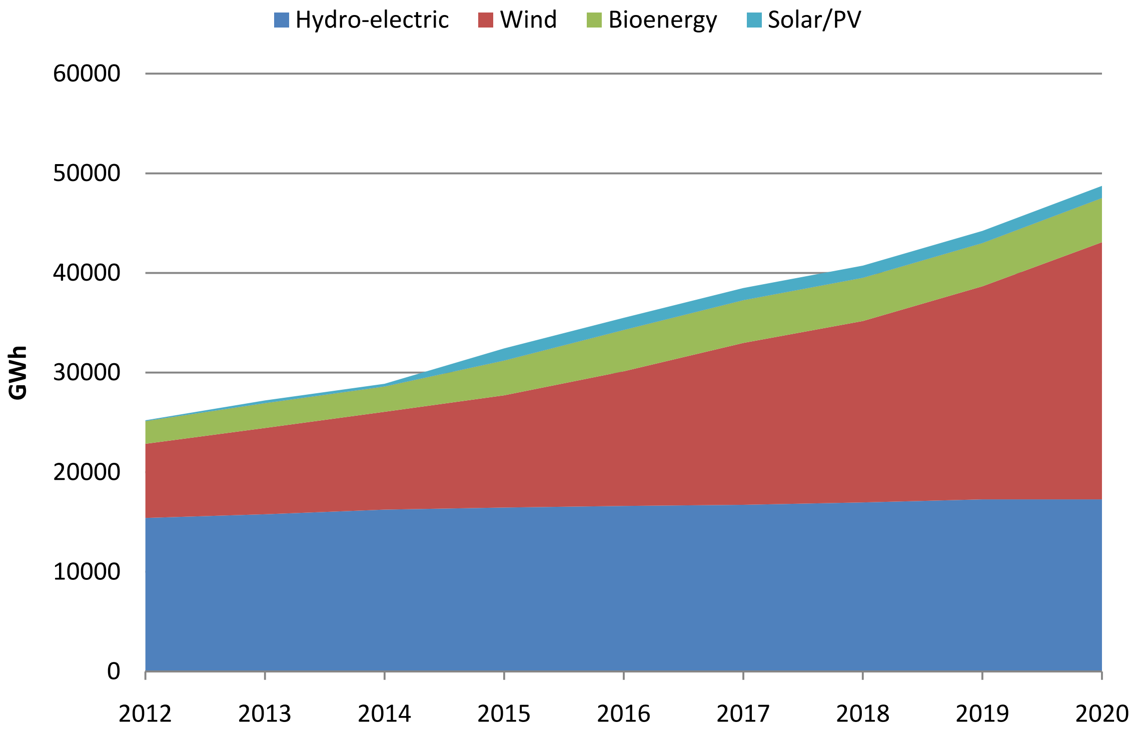
Future projections of the influence of the RET

The Large-scale Renewable Energy Target Scheme LRET scheme is on track to deliver 41,000 GWh by 2020 as required by the legislation. Current forecasts are for SRES to deliver approximately 8,200 GWh in 2020, Due to a range of uncertainties it is difficult to forecast the amount of generation from SRES, and the projections are indicative, given the assumptions made in this analysis.

As shown in Figure 3 the majority of the 2020 target is forecast to be met by wind (9,507 MW) and solar (511 MW) with other technologies playing a minor role.

[1] SKM (2012), *Benefits of Wind Energy in Australia*, report to the Clean Energy Council

- **Figure 3 Change in mix of renewables over time with the RET.**



The analysis indicates that investment in large scale renewable energy generation in the period to 2020 is largely driven by the RET, but that after 2020 (particularly after around 2025) the carbon pricing scheme is likely to act as the major spur for investment. In this sense, the RET scheme can be seen to be complementary to the carbon pricing scheme in that the RET is driving investment until the carbon price takes over as the main driver for investment sometime after 2020.

Expansion of renewable generation will continue to offset fossil fuel generation from existing sources. Over the period to 2020, coal fired generation is expected to be 12% lower as a result of the additional renewable generation, resulting in a fall in total generation from coal over the period. Gas fired generation will be around 13% lower as a result of the RET

One impact of the RET scheme is to change the mix of renewable energy generation away from a mix dominated by hydro-electric generation to contributions from a wide range of technologies.

Impact on electricity markets

The wholesale price[2] is projected to reduce by $9/MWh across the NEM in the period to 2030 due to the same factors outlined above Modelling indicates that for the same period, retail prices for residential customers will be $3/MWh lower on average than without the RET.

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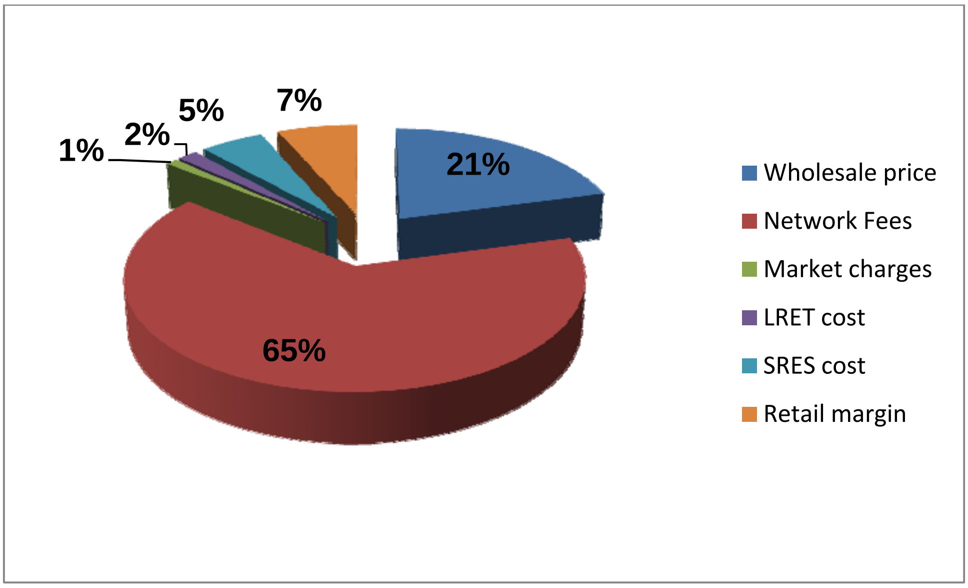
[2] The wholesale prices are lower compared to the case of no RET but this does not imply that the wholesale prices overall will be lower.

Electricity tariffs have increased sharply over the last 5 years and are expected to increase in the near future as a result of carbon pricing and increasing network fees. This has focussed debate on drivers of the increase in costs.

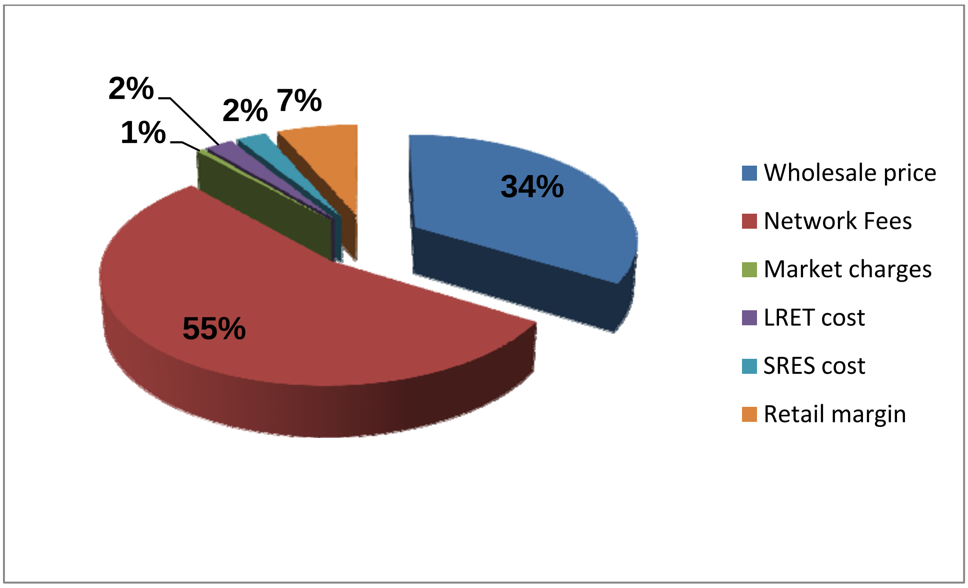
The components and impact on electricity tariffs are shown in Figure 4 and Figure 5 (note NSW shown by way of example). As can be seen the largest proportion and influence on electricity tariff are the wholesale prices and network fee components making up over 85% of the total electricity tariff. The proportion of the tariff attributable to the compliance costs[3] of the RET scheme is around 7% in 2012 In addition, wholesale prices and network fees (if existing cost trends continue) are projected to increase. However, the contribution from the RET scheme costs are expected to fall over time from 7% in 2012 to around 5% in 2020 and 2% in 2030.

- **Figure 4 Components of NSW Retail Tariffs for 2012**



[3] The compliance cost of the RET scheme will be passed on to end-users.

▪ **Figure 5 Components of NSW Retail Tariffs for 2020**



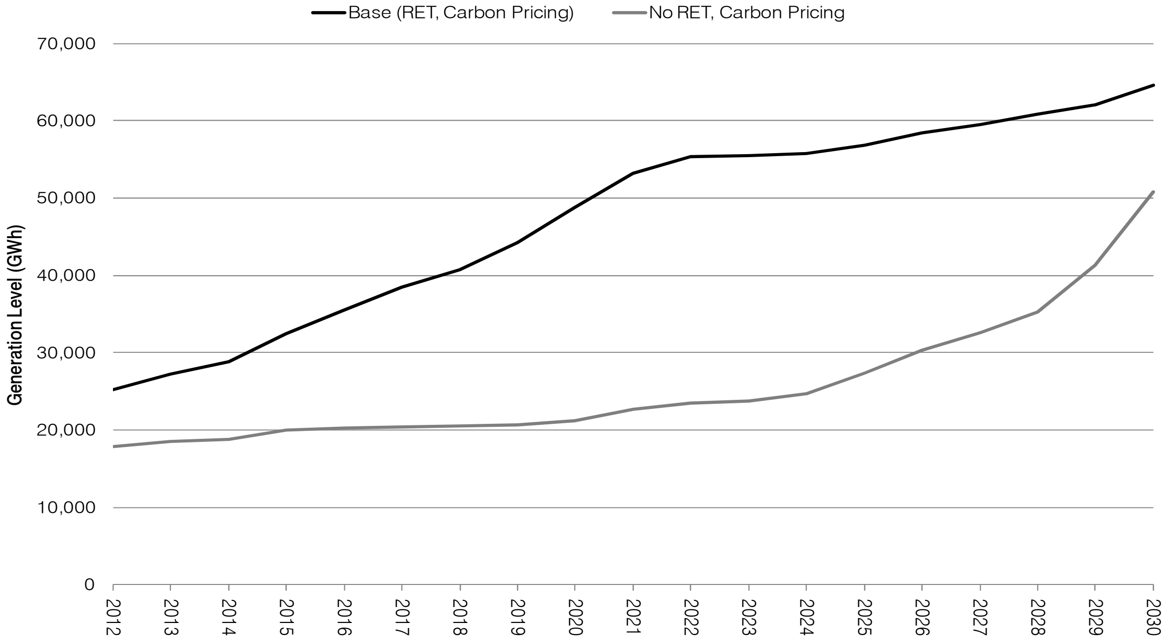
Other Impacts

The uptake of renewable energy generation over the last 10 years has reduced emissions by approximately 23 Mt CO_2e. The renewable energy target itself is responsible for around 20 Mt CO_2e or approximately 90% of this estimated electricity market emission reduction. Emission of greenhouse gases from electricity generation is projected to be around 20 Mt CO_2e per annum less with the RET scheme in place. The projected reduction in emissions when carbon pricing remains needs to be interpreted with care, as under carbon pricing with an emissions cap (from 2015/16 onwards), this would displace emission reductions occurring elsewhere (most likely from overseas sources). Most of the reduction is expected to come from the displacement of coal-fired generation.

Implications with no RET

Generation from renewable energy sources would have been considerably lower were it not for the RET scheme. Without the RET scheme, generation from renewable energy sources would have been around 6,300 GWh less in 2011 and around 27,000 GWh less in 2020. After 2020, the impact of carbon pricing would act as a boost for renewable generation, assuming carbon caps to achieve at most 550 ppm global concentrations are adhered to. This is illustrated in Figure 6.

Figure 6: Large scale renewable energy generation with and without the RET scheme



The level of renewable energy generation with the RET would have been lower if other support measures (such as the NSW Greenhouse Gas Abatement Scheme) had not also been implemented.

Without the RET, fossil fuel generation capacity would have been greater, both in terms of energy generated but also in additional plant being required. Without the RET, installation of additional fossil fuel generation would have resulted in higher carbon emissions. The RET should ensure that the majority of Australia's 2020 abatement target is achieved by action and investment in Australia. The cost of purchasing additional permits during the three years of the fixed price carbon price period if there was no RET is around $470 million on a net present value basis (using a 6% discount rate). The cost of purchasing international permits during the flexible price period from 2015 in the absence of the RET is around $6,100 million.

1. Introduction

A target mandating the purchase of new renewable energy generation by retailers has been in operation in Australia since 2001. The original scheme, called the Mandatory Renewable Energy Target (MRET) mandated a target of 9,500 GWh of new renewable generation by 2010. This evolved into the expanded Renewable Energy Target 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).

Other forms of assistance have also been provided to the renewable energy industry mainly in the form of grants to fund the capital cost of novel renewable energy technologies. However, the RET has provided the greatest incentive for the development of renewable energy in Australia.

The schemes have operated over ten years providing a sufficient period of time to assess the outcomes of the target scheme. The Clean Energy Council commissioned SKM MMA to study the outcomes of the target scheme. Impacts on investment, wholesale and retail electricity prices and emissions were examined in this study. The findings are recorded in this report.

2. Policy Developments

2.1. Evolution of the Renewable Energy Target Scheme

The original target scheme, called the Mandatory Renewable Energy Target Scheme (MRET) mandated a target of 9,500 GWh of new renewable generation by 2010. From 2008, an additional state based scheme, the Victorian Renewable Energy Target Scheme was added, which mandated an additional 5% of Victoria's load for renewable generation[4]. Both schemes were replaced in 2009 by the expanded Renewable Energy Target Scheme, which increased the mandated amount to around 45,000 GWh.

In 2011, concerns that the rapid uptake of small scale systems would lead to the crowding out of investments in large scale systems led to the splitting of the target into the Small-scale Renewable Energy Scheme (SRES), covering systems of less than 100 kW[5] and electricity displacement technologies, and the Large-scale Renewable Energy Target (LRET) scheme.

The expanded LRET imposes a target of 41,000 GWh of additional renewable energy from large-scale generation sources by 2020. The targets are given in Figure 7. The dip in the target trajectory apparent in 2014 is due to an upward revision in the 2012 and 2013 targets, which was triggered by the creation of more than 34.5 million RECs by the end of the 2010 calendar year. The legislation allowed an upward revision of the LRET target in 2012 and 2013 if this trigger was activated, and this is offset by a downward revision of the target between 2016 and 2019.

Generation from small-scale plant such as solar water heaters or rooftop PV systems contributes to the Small-scale Renewable Energy Scheme (SRES), and the combined renewable generation from the large-scale and small-scale schemes is expected to exceed the 45,000 GWh target of their predecessor, the expanded MRET scheme. The LRET scheme is otherwise similar to the MRET scheme in terms of issues such as banking of certificates and project eligibility periods.

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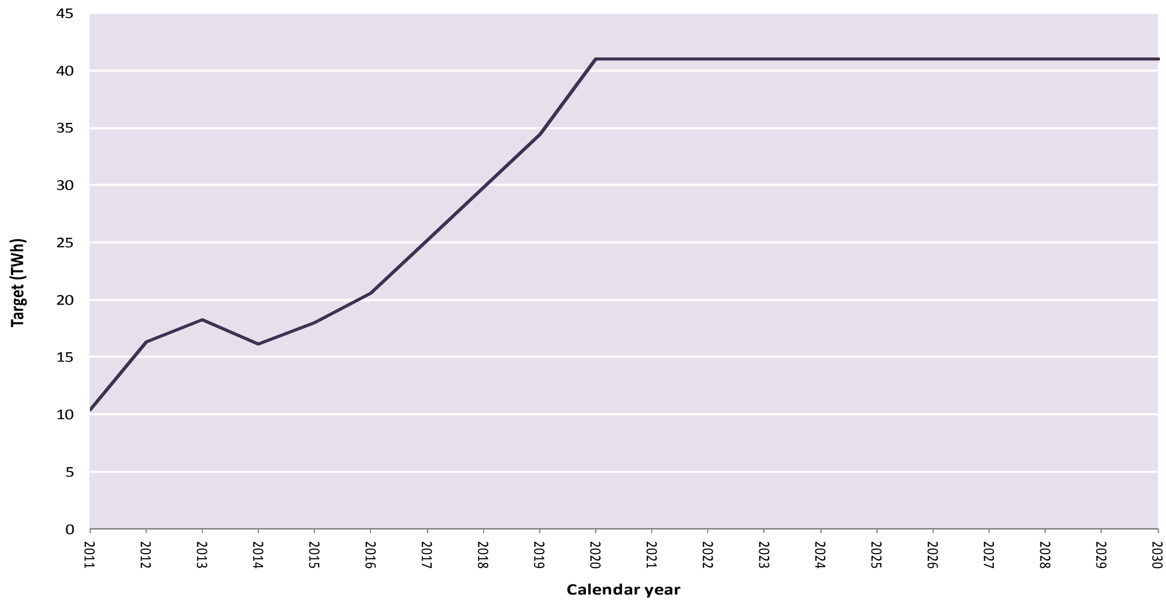
[4] At the time, both NSW and Western Australia were considering their own renewable energy target schemes. These did not proceed when the RET scheme was established.

[5] To be considered small scale and part of the SRES, the eligibility criteria are as follows: Solar PV systems - not more than 100 kW and electricity output less than 250 MWh; wind turbines - not more than 10 kW and electricity output less than 25 MWh; hydro-electric systems – not more than 6.4 kW and electricity output of less than 25 MWh.

- **Figure 7: Targets under the LRET scheme**



In terms of SRES, there is no target and the liability for purchase of small-scale technology certificates (STC) is set by the Clean Energy Regulator each year and the price is capped at $40/ STC.

2.2. Other Support Measures

Queensland Gas Electricity Generation Target is designed to diversify the energy mix for the coal rich state. The scheme began on 1 January 2005 and was to continue for 15 years. It requires electricity retailers to source at least 13% of their energy from gas-fired generation. A Gas Electricity Certificate (GEC) is created for every MWh of eligible gas-fired electricity and is required to be surrendered to the Regulator by Queensland electricity retailers and other parties. The scheme allows for some flexibility, with liable entities able to choose to create either GECs, or alternatively New South Wales Greenhouse Gas Abatement Certificate (NGAC), depending on the respective markets. In later legislation, the target was increased to 15% by 2010, with the option to further raise it to 18% depending on the design of the carbon pricing scheme. In this review, the target was modelled to increase to 15% by 2010 and subsequently increase to an 18% target by 2020 in a linear fashion.

New South Wales GGAS began on 1 January 2003 for New South Wales and 1 January 2005 for the Australian Capital Territory and ceases at the commencement of a carbon pricing scheme. The scheme sets and regulates mandatory emissions abatement targets on both the production and use of energy. A benchmark was established state-wide, initially at 8.65 t CO_2e per capita, with this target dropping linearly to 7.27 t CO_2e from 2007 until the close of the program. Under the scheme, eligible participants can create NGACs by electricity generation activities, carbon sequestration activities, demand side abatement activities or large user abatement activities. These certificates are each worth the equivalent of one tonne of carbon dioxide (CO_2) equivalent emissions. Retailers and other parties involved in the direct sale of electricity are required to surrender certificates to the Compliance Regulator (IPART) for a benchmark amount of CO_2. The penalty for non-compliance is $11.50 per tonne of CO_2The penalty is adjusted annually in line with the consumer price index. Liable parties may surrender renewable energy certificates in substitution for NGACs, and importantly, NGACs can be created anywhere in the NEM.

Green Power scheme is a national initiative that complements the RET. Consumers may purchase a percentage of their electricity from renewable sources other than those already surrendered to the renewable target scheme.

Feed in Tariffs (FiT) have been implemented in every state in Australia. In all states, apart from Tasmania, legislation has been introduced setting the tariff structure. The schemes also varied in terms of type of scheme (i.e. gross/net) and the level of incentive provided. As outlined in the recent review by IPART[6] for the NSW feed in tariff, each scheme has ranges in price from a high of 60 cents/kWh in NSW and Victoria initially, down to more recent determination of a minimum retail payment of between 7 and 10 cents/kWh (SA, WA and now NSW). These are depicted in a comparison table shown below provided in IPART's review.

The FiT schemes have resulted in more installations of PV/solar systems across Australia but most notably in NSW driven by the 60 cent/kWh feed in tariff.

- **Table 1: Range of feed-in tariffs across Australia[7]**

Scheme	Type	FiT	Opening date	Closing date	Duration
Qld Solar Bonus Scheme	Net	44	Jul-08	Jun-12	2028
NSW Solar Bonus Scheme	Gross/net	60	Jan-10	Nov-10	2016
NSW Solar Bonus Scheme	Gross/net	20	Nov-10	Apr-11	2016
Vic Premium FiT	Net	60	Nov-09	Sep-11	2024
Vic Transitional FiT	Net	25	Jan-12	-	2016
Vic Standard FiT	Net	Retail price	Jan-09	-	-
WA FiT	Net	40	Aug-10	Jun-11	10 years
WA FiT	Net	20	Jul-11	Aug-11	10 years
WA RE Buyback Scheme	Net	70% to 100% of retail price	-	-	10 years
ACT FiT	Gross	50.05	Mar-09	Jun-10	20 years
ACT FiT	Gross	40.04	Mar-09	Jun-10	20 years
ACT Micro-generator FiT	Gross	45.70	Jul-10	Jun-11	20 years
ACT Medium Generator FiT	Gross	34.27	Feb-11	Jul-11	20 years

[6] Solar feed-in tariffs, Setting a fair and reasonable value for electricity generated by small-scale solar PV units in NSW, Energy — Final Report, March 2012

[7] Note the table has not been updated with recent changes in Fit schemes in Victoria, NSW or Queensland as they have not been included in the modelling.

Scheme	Type	FiT	Opening date	Closing date	Duration
ACT Medium and Small FiT	Gross	30.16	Jul-11	Jul-11	20 years
SA Solar Feed-in Scheme	Net	44 plus retail price	Jul-08	Sep-11	2028
SA Solar Feed-in Scheme	Net	16 plus retail price	Oct-11	Sep-13	2016
SA Solar Feed-in Scheme	Net	Retail price	Oct-13	-	-

Source: IPART[2.]

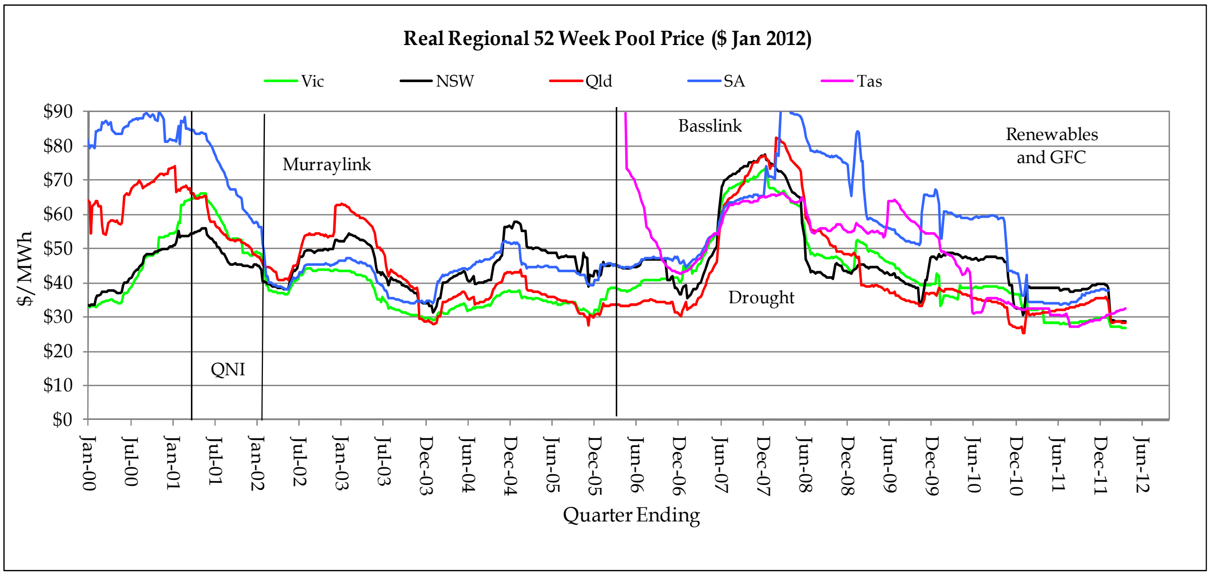
Solar Flagships Program was designed to support the development of large scale, grid connected solar power stations in Australia. It is a funding program to help commercialise solar projects administered by ARENA (Australian Renewable Energy Agency). As of July 2012, the AGL 150 MW photovoltaic project spread over two locations in NSW were the only projects to receive funding under this scheme while the 250 MW Solar Dawn project is under consideration from ARENA.

South Australia also introduced a renewable energy target of 20% by 2014 in 2008. South Australia is due to meet this target by 2013.

2.3. Electricity Market Developments

Over the period since 2000 electricity spot prices have fluctuated due to many factors. The development of interconnectors has enabled lower overall electricity spot prices to be distributed. This is evident from Figure 8 which depicts the spot market fluctuation and new interconnector introduction since 2000. After 2002 there was period of relatively stable and low prices, interrupted only by the effects of the drought, which led to restrictions in the use of cooling water for coal-fired generators, and also resulted in the partial closure of the Tarong power plant in Queensland, as well as reduced output from hydro plants on the mainland and Tasmania. Prices peaked in the second half of 2007 and the first half of 2008 as a result of these supply side pressures, although they have since been trending downwards and have now reached historically low levels, not seen since 2006. The factors driving the subdued prices recently observed in the NEM are a combination of reduced demand, due to the GFC's impact on the global economy, mild weather in the last couple of years, and increasing penetration of large-scale renewable energy generation (mainly wind farms) in the NEM.

▪ **Figure 8: NEM spot price trends**

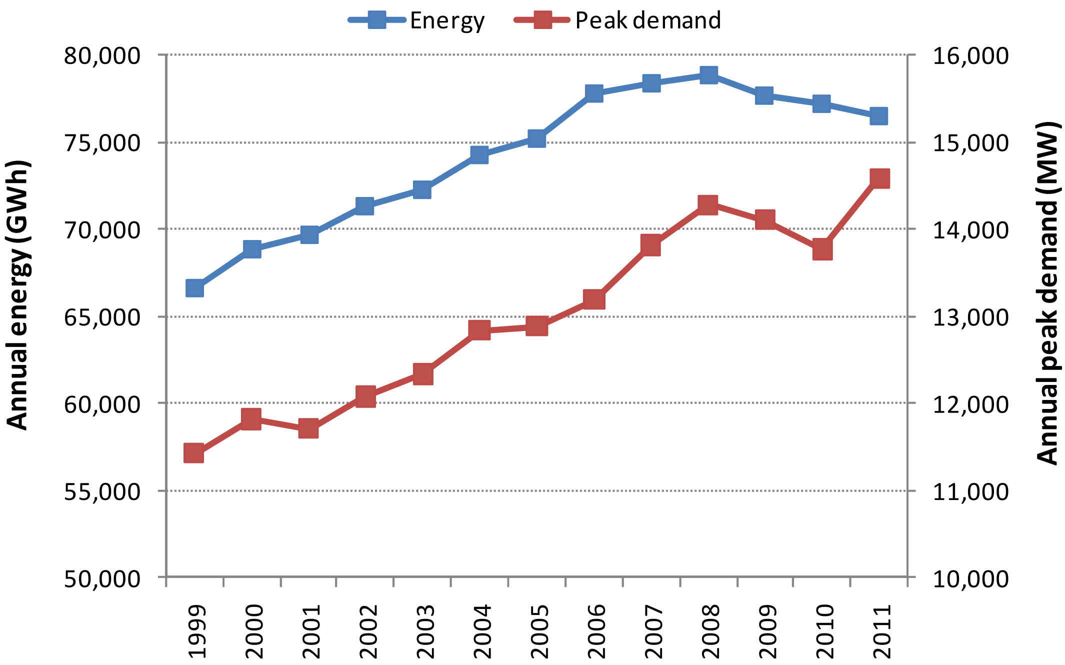


It is evident from the last year of spot price data that volatility has subsided significantly. The current period in the NEM is unprecedented with respect to spot price volatility in that all five regions are experiencing volatility levels that are at, or close to record lows. The only historical occurrence of volatility that simultaneously extended across regions was in early 2002, when low demand resulting from a very mild summer affected spot prices in both Victoria and South Australia. This suggests that the current drivers of the low volatility, namely low demand growth and increased penetration of renewable energy, are having far reaching effects that are extending across the entire NEM.

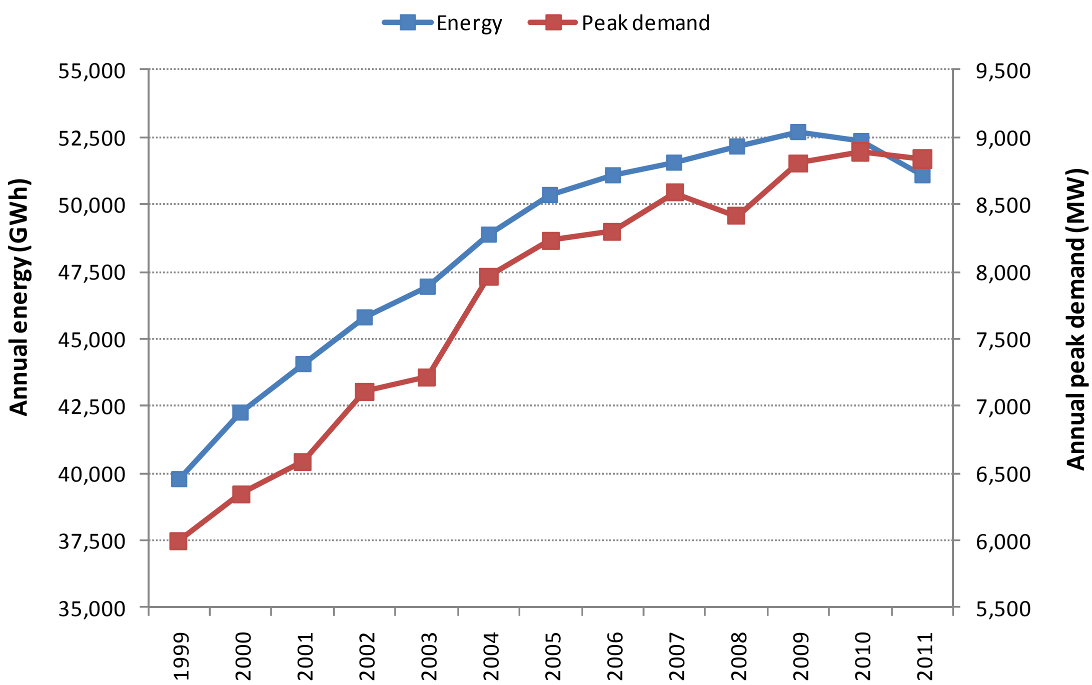
In terms of demand over the period since 2000, there has been considerable growth in both average energy and peak demand in all regions. It should be noted that in the past 2 -3 years both energy and peak demand has either stabilised (i.e. Queensland) or reduced, primarily due to impacts of the GFC on growth in the economy. Peak demand has grown at a stronger rate than energy demand across most of the regions over this time due to increased penetration of air conditioners for cooling. Hence, when mild conditions occur, peak demand will be lower, this has been experienced in Victorian over the past 2-3 summers. Figure 9 and Figure 10 depict the growth in energy and peak demand for NSW and Queensland.

It should be noted that the maximum demand in NSW for the summer of 2012 was only 11,886 MW, a reduction from the previous year's peak demand of over 18%. Unlike other regions the peak demand in NSW has fluctuated between summer and winter peaks. Other regions tend to be either summer peaking or winter peaking.

- **Figure 9: New South Wales annual energy and peak demand**



- **Figure 10: Queensland annual energy and peak demand**



Capacity across the NEM has grown steadily, as has the development of interconnectors to take advantage of non coincident peak demand periods. The development of capacity has been mainly focussed on coal and gas (peaking and combined cycle plant) with some development occurring across all regions.

The uptake of roof-top solar has increased dramatically over the period driven by the RET and state based feed-in tariffs. The rapid uptake of these systems has contributed to grid based electricity use being lower in both the NEM[8] and the SWIS[9] to the extent that demand in both grids have been relatively flat since 2008-09.

[8] See AEMO (2012)
[9] See WA IMO (2012)

3. Method and Assumptions

Uptake of renewable energy under the RET may have a number of impacts on energy markets. The impacts could include:

- Deferral of new investment in high emission fossil fuel generation preventing the lock in of emissions intensive plant that would make it difficult to meet legislated carbon reduction targets.
- Reducing electricity demand - The uptake of solar water heaters and small scale roof top PV systems contributes to the reduction in electricity demand by displacing the need for grid based electricity.
- Reduced gas demand - to the extent that large scale renewable energy generation has reduced gas-fired generation (typically the last plant dispatched in the system). Uptake of solar water heaters may have also reduced the demand for gas for residential use.
- Spread the location of generation to a greater range of regions, in some cases improving the efficiency of use of transmission systems and reducing system losses. In other cases, losses may have increased.
- Higher levels of intermittent generation may have had an impact on ancillary service requirements, potentially increasing system costs[10]. However, these impacts may have been minor given the dispersed deployment of renewable energy generation. Further, high levels of intermittency may also act to reduce the use of market power to set prices as intermittency makes it difficult to predict the supply /demand balance.

The RET scheme has a range of impacts on industry as well. Although there have only been some manufacturing activities directly attributable to the scheme, other service activities have been stimulated increasing employment in those activities. Development of these activities may have led to the development of new export industries. Furthermore, income earnt from wind farms has stabilised the financial prospects of farm enterprises[11].

Other economic benefits may have been created especially in the context of a carbon constrained world. These benefits include the development of new capabilities in deploying low emission technologies and gradual cost reductions through learning by doing and economies of scale in production. Although many components that make up renewable energy generation are imported, there is still significant scope for cost reductions in the assembly, distribution, erection and financing of renewable energy generation. These benefits will eventually lead to lower costs (than would have occurred otherwise) in meeting future carbon emission caps.

This section provides a summary of the modelling approach and key assumptions used in assessing the impacts of the RET scheme.

3.1. Overview

The analysis needs to consider as a minimum the impacts to date and projected impacts to 2030 on:

- Energy market especially generation, capacity installed, level of investment, carbon abated and employment generation, and

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[10] In the simulation modelling, additional ancillary costs from high penetration of wind generation have been modelled as an increase in operating and maintenance costs, starting at $5/MWh and increasing to $15/MWh.

[11] SKM (2012), *Benefits of Wind Energy in Australia*, report to the Clean Energy Council

- Wholesale spot price in the NEM and WEM and impact on retail prices.

In addition to these outputs, we propose as an option to provide a broader analysis of the beneficial impacts of the RET scheme.

We adopt statistical and simulation approaches to unlock the impacts. The statistical approaches will be used to unlock the impacts on demand from the RET scheme, verify historical outcomes and to estimate broader impacts on deployment costs, employment opportunities and energy price impacts. The simulation model will be used both to backcast the impacts of the RET scheme, particularly unlocking the interactions with other schemes to derive net impacts, and to simulate future outcomes for industry and electricity prices.

3.2. Modelling historical outcomes

A range of statistical and simulation tools will be deployed to obtain insights into what has been delivered by RET to date and what it is likely to be delivered in future.

3.2.1. Statistical approach

Regression techniques were deployed to obtain insights into the impacts of the RET scheme. The statistical analysis was confined to determining the impacts of the RET on wholesale and retail prices, electricity demand (grid based demand), renewable energy costs and emissions. The aim of the analysis is to factor in whether the RET scheme has had an impact on these variables taking into account the impact of all other factors.

In determining the impact, it is important to account for the relative impact of other policy measures as well as fundamental drivers.

Wholesale price impact

Studies have pointed to the RET having an impact on wholesale electricity prices[12], and through this, an impact on retail prices. Based on SKM's understanding of the drivers affecting recent price trends, the impact can be mapped by the following function:

$$WPi=F(Di, Fi, GPi, NPi, REGi)$$

Where *WPi* is the wholesale price in period *i*, *Di* is electricity demand in period *i*, *Fi* is the composite fuel price index (covering coal and gas prices), *GPi* is the Queensland Gas Electricity Certificate Price in period *i*, *NPI* is the NSW Greenhouse Gas Abatement Scheme certificate price, and *REGi* is the ratio of eligible renewable energy generation capacity to total fossil fuel generation capacity.

The analysis can be done on a quarterly basis as most of the input data is available on a quarterly basis. A seasonality factor is added to remove the impacts of seasons. All price variables are converted into real mid 2012 dollar terms by using the capital city CPI data.

Data on level of renewable energy and fossil generation capacity is taken from published AEMO data for scheduled generation. The fuel price index will be developed based on spot prices for natural gas (e.g. Victoria) and coal (export fob price – assume opportunity cost) weighted by the share of generation for each fuel type in each quarter.

The analysis is applied only to NEM data, and will be applied on a regional basis. The analysis was applied to NSW and South Australia data[13].

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[12] Nelson and Simshauser (2011)

Electricity demand impact

Electricity demand growth has waned over the past four years. The RET scheme may have had an impact on electricity demand as the uptake of solar water heaters and small scale roof top PV systems reduces the demand seen by the grid (as some house hold load is self supplied).

Other factors may also impact on electricity demand. Network fees have increased substantially leading to higher retail prices. Economic growth has stalled and some industrial loads have disappeared due to subdued demand and high exchange rates.

To model the impact of the RET on stationary energy demand, a two stage process was adopted. First, to model the impact on electricity demand from key explanatory variables as follows:

$$DDi = F(RETPi, GDPi, Ti, SOLi)$$

Where *DDi* is the demand in year *i*, *RETPi* is the retail price index in year *i*, *GDPi* is the measure of income in year *i*, *Ti* is the time trend (meant to capture a shift towards electricity generation due to uptake of new technologies) and *SOLi* is the level of small scale solar PV generation. The model is specified in log linear form as follows:

$$Ln(DDi) = \alpha + \beta_1 Ln(RETPi) + \beta_2 Ln(GDPi) + \beta_3 Ln(Ti) + \beta_4 Ln(SOLi) + ei$$

The period of the analysis is from 1997 to 2011, with the analysis conducted at a State level.

This stage would help pick up the impact of increasing levels of self generation from solar PV systems, particularly over the last 5 years.

The second stage involves removing the contribution of the RET compliance cost from the retail price index. The demand would then be re-estimated from altered retail price. The change in demand will provide an indication of the impact of the price change attributable to the RET.

3.2.2. Backcasting

The backcasting process involved in replicating historical outcomes to enable an analysis on what may have happened if certain policies or renewable support measures were not introduced for this analysis. Three back casting cases were examined:

1) Scenario 1: Backcast with all renewable energy support policies implemented - this provides a modelled outcome of the actual world so that the following cases can be compared;
2) Scenario 2: Backcast to 2001 with no support policies implemented this provides the extreme case where there is no RET, no feed in tariff or other renewable polices. Therefore renewable development would be based on the economics of renewable generation in the systems considered (i.e. NEM, SWIS, etc); and
3) Scenario 3: Backcast with no RET policy in place but with the other /historical renewable support policies implemented.

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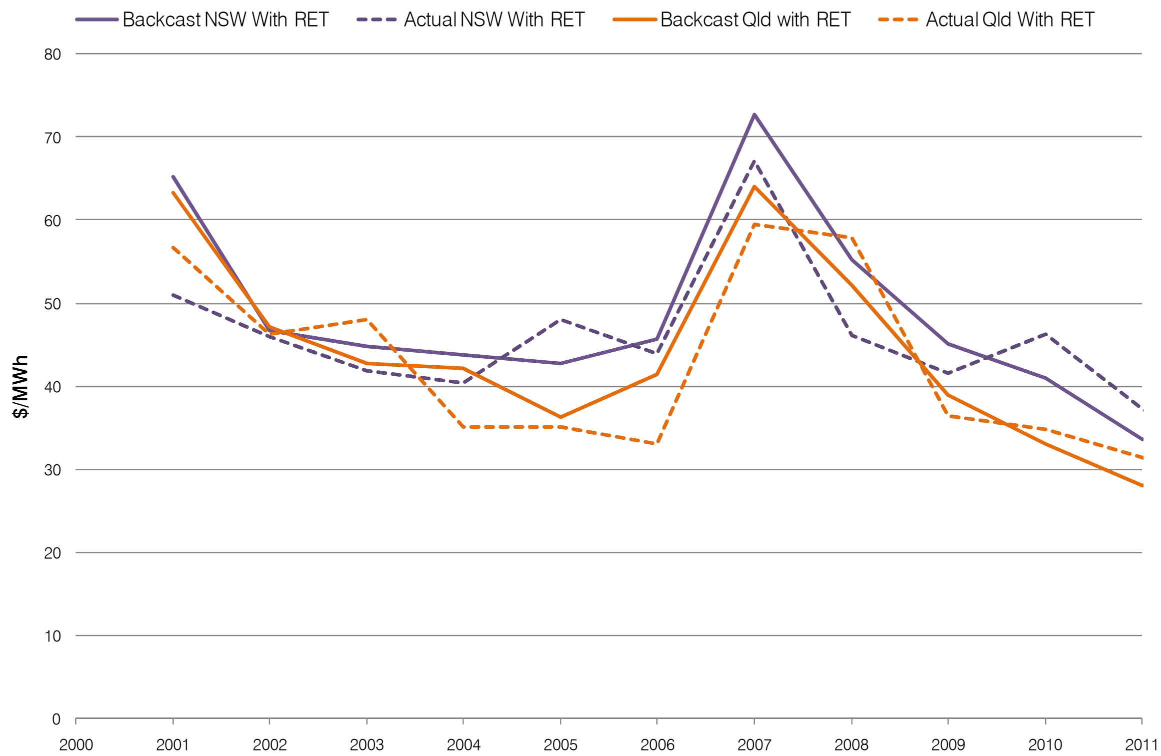
[13] These states were chosen because NSW tends to sets the price in the eastern states of the NEM, and because South Australia has had the greatest penetration of large-scale renewable energy under the RET. These states are not directly affected by the Queensland GEC scheme, uptake of gas-fired generation in Queensland will have flow through impacts on prices in other regions of the NEM.

These three scenarios will allow impacts of the RET and other renewable policies to be assessed in a historical context. For evaluating the net impacts of the RET scheme the outcomes from Scenario 3 and Scenario 1. The difference in impacts between Scenarios 2 and 3 will provide the impacts of other policy measures supporting renewable energy.

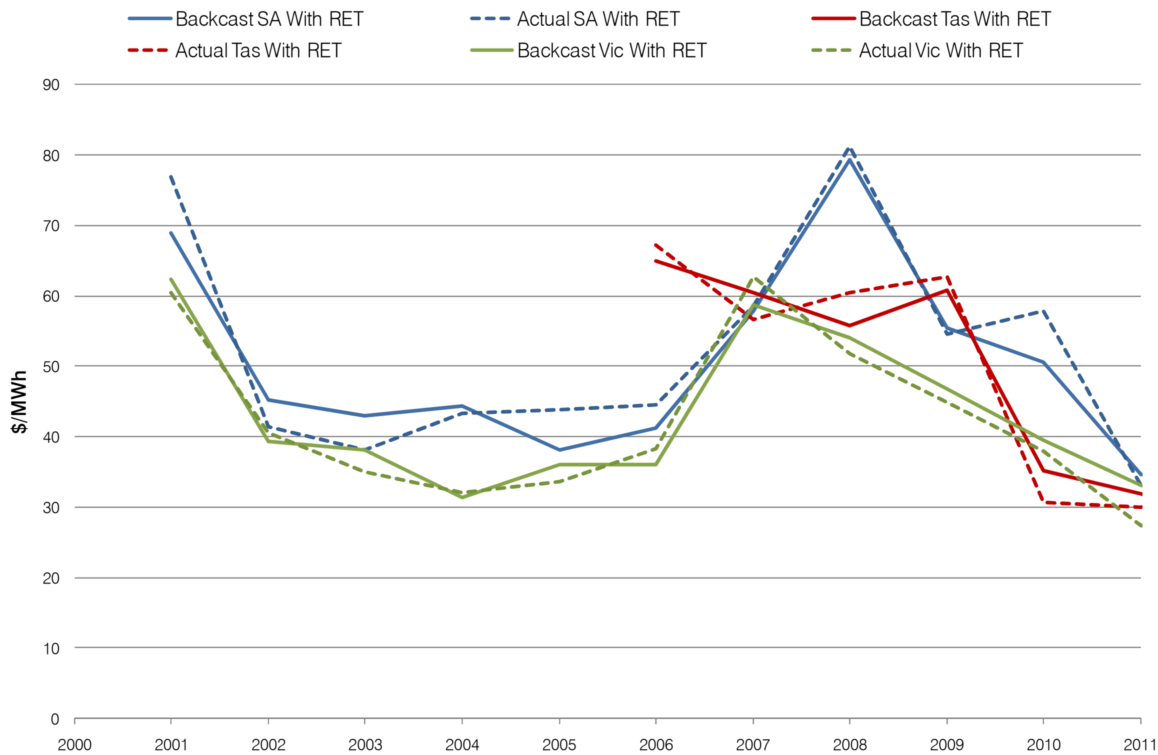
In performing the back casting the base case, or Scenario 1, was undertaken to achieve similar pricing outcomes to history based on the time weighted average annual prices. STRATEGIST was used to model this case with a focus on the changes in bid prices to derive an appropriate outcome. The results of this process from 2001 to 2012 financial year are shown below for NSW and Queensland South region (historical prices are the dotted lines) and then for Victoria, South Australia and Tasmania (see Figure 12).

The modelling is not exact due to the actual bidding and dispatch process being more refined than the STRATEGIST modelling process. Tasmania is only displayed post Basslink commencing operations (i.e. 2006 onwards). Overall the back casting provided a pricing outcome within +/- 5 % of the historical annual prices over the period 2002 to 2012 and this was considered to be representative of the historical prices. Using this base case model, the back casting for scenarios 2 and 3 was then used to compare the impact of the renewable policies implemented.

- **Figure 11: Historical actual and modelled wholesale prices for NSW and Queensland**



- **Figure 12: Historical actual and modelled prices for other NEM States**



3.2.3. Simulations of future impacts

SKM-MMA used its market simulation model of the key energy markets (NEM, SWIS, NWIS and DKIS, and gas markets) to estimate the future impacts on the electricity markets of the RET scheme.

Our approach to modelling the electricity market, associated fuel combustion and emissions is to utilise externally derived electricity demand forecasts (either actual historical data for the backcasting analysis or the latest AEMO projections (adjusted for the embedded generation component) for the forecast work in our STRATEGISTmodels of the key electricity markets.

The STRATEGIST model is a multi-area probabilistic dispatch algorithm that determines dispatch of plant within each year and the optimal choice of new plant over the period to 2050. The model accounts for the economic relationships between generating plant in the system. In particular, the model calculates production of each power station given the availability of the station, the availability of other power stations and the relative costs of each generating plant in the system.

The model projects electricity market impacts for expected levels of generation for each generating unit in the system. The level of utilisation depends on plant availability, their cost structure relative to other plant in the system and bidding strategies of the generators. Bids are typically formulated as multiples of marginal cost and are varied above unity to represent the impact of contract positions and price support provided by dominant market participants. However, for this study we propose to use short run marginal cost bidding as the main bidding driver to simplify the analysis.

New plant or energy efficiency programs, whether to meet load growth or to replace uneconomic plant, are chosen on two criteria:

- To ensure electricity supply requirements are met under most contingencies. The parameters for quality of supply are determined in the model through the loss of load, energy not served and reserve margin. We have used a maximum energy not served of 0.002%, which is in line with planning criteria used by system operators.
- Revenues earned by the new plant/energy efficiency program equal or exceed the long run average cost of the new generator.

Key results obtained from the modelling include:

- Wholesale and retail market prices (including additional expenditure by households).
- Delivered customer prices for each customer class.
- Direct costs to retailers.
- Dispatch of generation by fuel type.
- Level of greenhouse gas emissions (which can be provided by State, generation technology or fuel type).
- Investments in new generation.
- Resource costs (fuel, capital and operating costs).
- Renewable energy generation by technology (including small scale generation, solar water heaters and heat pumps).

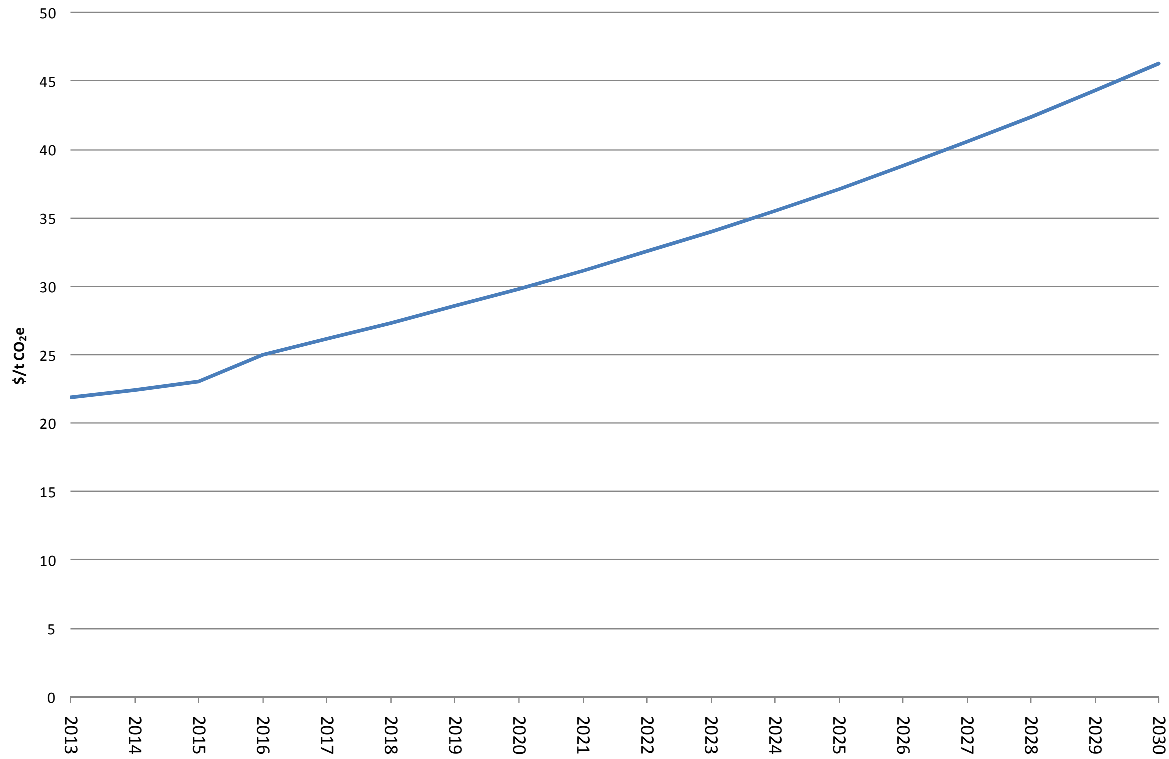
3.3. Assumptions

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

- The market is assumed to operate to maximise efficiency and is made up of informed, rational participants.
- Capacity is installed to meet the target reserve margin for the NEM, SWIS, NWIS and the DKIS as long as plants are profitable after entry.
- Any changes in pool prices will flow through to retail prices. Price increases are therefore borne by the broad customer base.
- Availability, heat rates and capacity factors of all plants in the NEM, SWIS, NWIS and DKIS (including non-renewable generators) are based on historical trends and other published data.

Carbon price assumptions are illustrated in Figure 13 and are consistent with the Treasury-5 modelling.

▪ **Figure 13 Carbon price path for Government policy scenario, \$/t CO_2e**



Details of all other assumptions are contained in Appendices A to E.

3.4. Scenarios

The analysis is being undertaken for the period from 2001 to 2030. Seven scenarios were modelled, with 4 scenarios used for projection of future impacts and 3 of the scenarios used for backcasting. All scenarios were based around the median demand forecasts, although there were variations on the demand faced by the grid depending on the uptake of embedded renewable generation (e.g. roof-top PV systems). Median fuel and capital costs assumptions were also used.

The three backcasting scenarios are:

- Base scenario 1: Backcast to 2001 with no support policies implemented.
- Base scenario 2: Backcast with other renewable energy support policies but no RET scheme.
- Policy scenario 1: Backcast with all renewable energy support policies implemented (this will provide the actual world outcome)

In terms of projected future price, energy market and industry impacts, the following scenarios are to be modelled:

- *Current policy scenario* - the proposed RET and carbon price. This will include the LRET/SRES split and with the planned carbon pricing mechanism under the Clean Energy Futures Package. Other support measures as implemented (ARENA and CEFC funding will also be included).
- *Carbon price only scenario* - the carbon price alone with no RET scheme. Renewable energy generation will expand only from the higher electricity prices due to the carbon pricing scheme.

All other support measures remain in place. This will provide insights into the net impact of the RET scheme.

- *No carbon price and no RET scenario* which will form the reference case.

The analysis was conducted for the period from 2001 to the end of 2011 for the backcasting simulations and from 2012 to 2030 for the projection analysis.

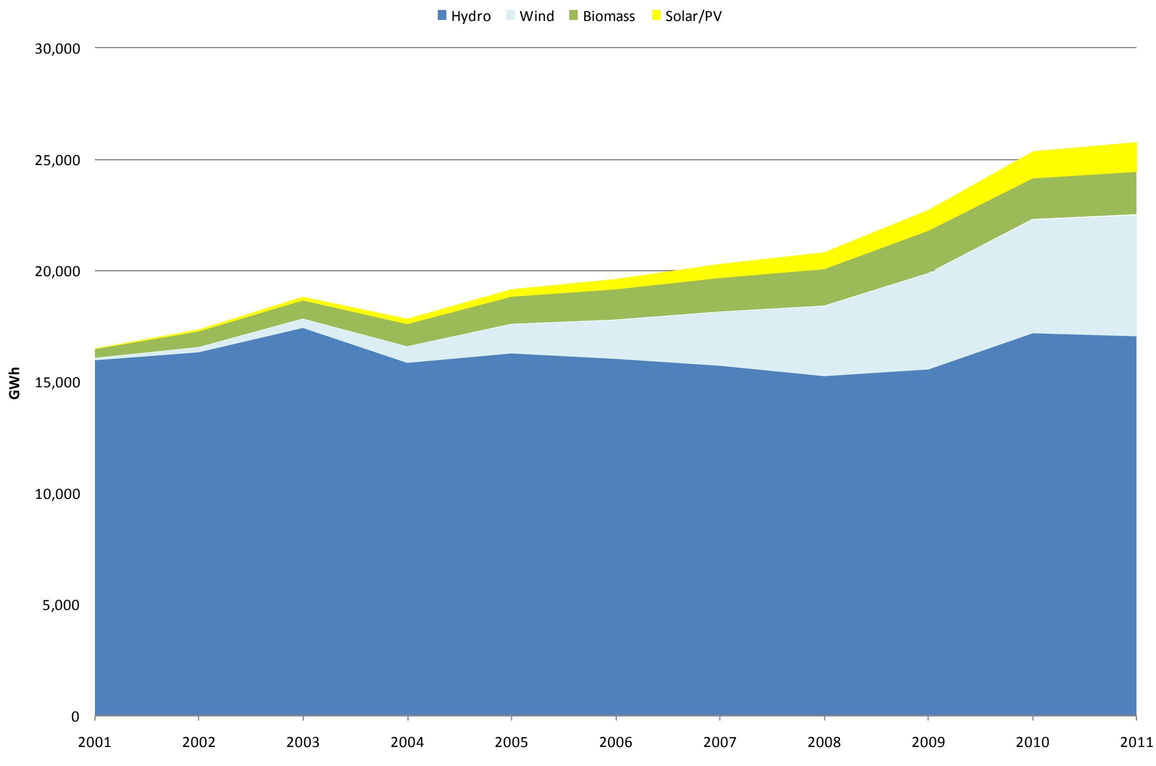
4. Historical Impacts

4.1. Renewable Energy Generation

The impacts of the scheme are driven by the level of uptake of renewable generation. Although the target for renewable energy generation rose over the period to 2011, the actual impact will depend on the growth of renewable energy generation, including from existing hydro-electric generators, relative to the growth rate in demand

The level of renewable energy generation has increased as a result of the RET scheme (see Figure 14). Most of the increase has occurred over the last 5 years. Prior to 2007, renewable energy generation was stable: the target ramped up at a low level in the period to 2005 (to allow time for the industry to adjust), and because a prolonged dry period generation from hydro-electric facilities was reduced. The recovery of water inflows over the last two years combined with an acceleration of the development of wind farms and strong growth in uptake of solar systems (water heaters and PV systems) has led to a sharp growth in total renewable energy generation.

- **Figure 14: Renewable energy generation in Australia**



Source: SKM MMA data bases; ORER; Clean Energy Regulator. Note: Solar/PV technology includes the electricity displacement from uptake of solar water heaters.

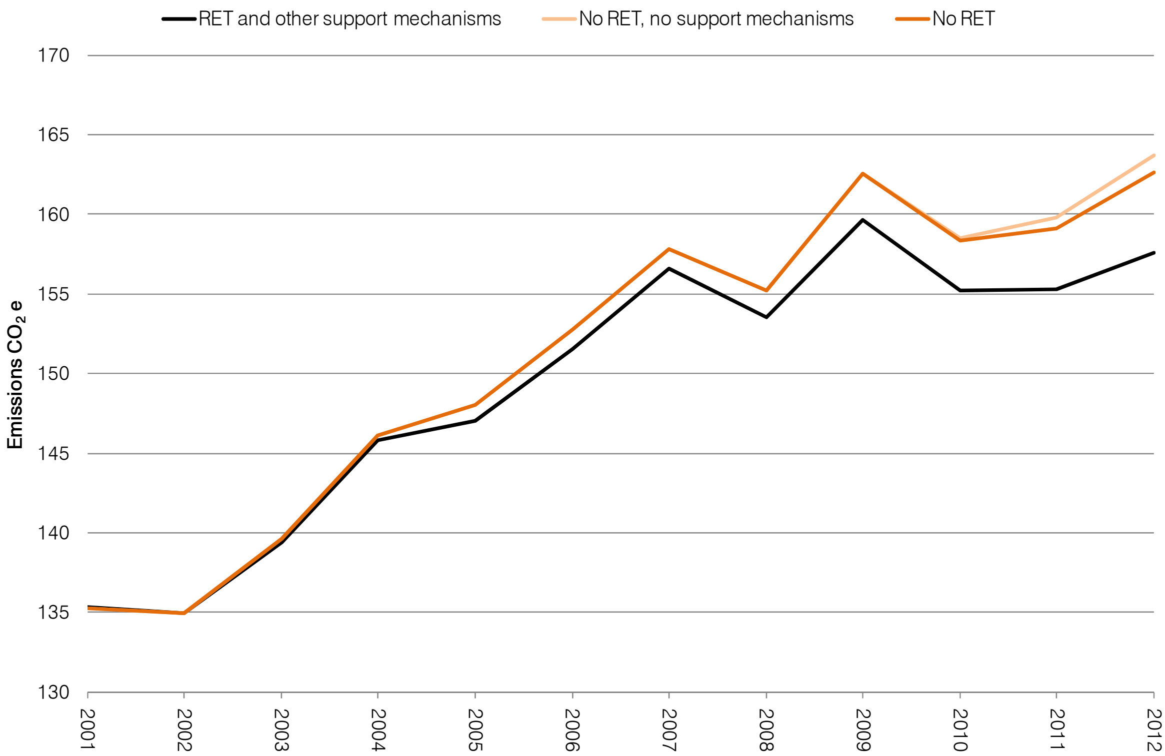
Despite the recent sharp growth, the proportion of total electricity generation from renewable energy has remained relatively stable. At the beginning of the scheme in 2001, renewable energy was supplying around 9.0% of total generation. At the end of 2011, renewable energy was accounting for around 10.9% of total generation. The growth rate of renewable energy generation was only modestly higher than the growth rate in demand. Hydro-electricity generation is still the dominant source of renewable energy generation. Wind generation has experienced the fastest growth rate, now accounting for around 21% of total renewable energy generation. Solar (including the energy

from solar water heating) now accounts for around 5% of total generation. Biomass now accounts for 7% of total generation compared with 2% in 2001. The proportion of hydro-electric generation has fallen from 97% of the total in 2001 to 66% in 2011.

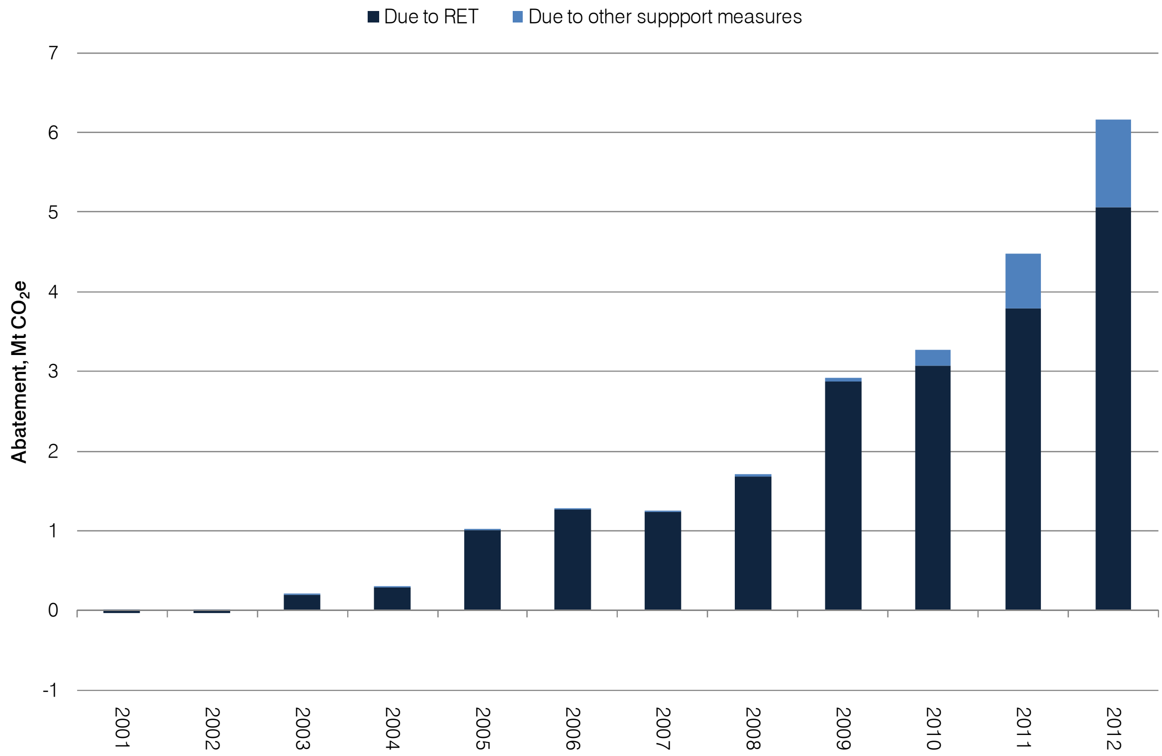
4.2. Emissions

In the back casting analysis, there has been a relatively large decrease in emissions across the Australian stationary energy sector. This is due to the displacement of fossil fuel generation by renewable energy generation. Figure 15 and Figure 16 illustrate this over the 2001 to 2011 period. The additional renewable energy generation from all support measures resulted in a cumulative abatement of emissions in that period of around 22.5 Mt CO_2e, with around half of this abatement occurring from lower fossil fuel (mainly coal-fired) generation in NSW, and around one-third from lower gas and coal fired generation in South Australia. The remainder is spread equally across the other states.

- **Figure 15: Historical emissions**



- **Figure 16: Abatement due to the RET and other support measures**



The modelling indicates that over the 2001-2012 period approximately 90% of the emission abatement from additional renewable generation is attributable to the RET impact, with the remainder aligned to renewable generation driven by other support mechanisms. Using the 2012 additional emissions with no support mechanism of 6.2 Mt CO_2e and a carbon price of $23/t gives a cost to the community of $140 million for those emissions.

Without the RET scheme emissions from electricity generation in 2012 would have been around 4% higher. The additional emissions from electricity generation would have meant the national emissions level would have been over the levels required to meet the Kyoto Targets by around 2 to 3 percentage points.

4.3. Investment Trends

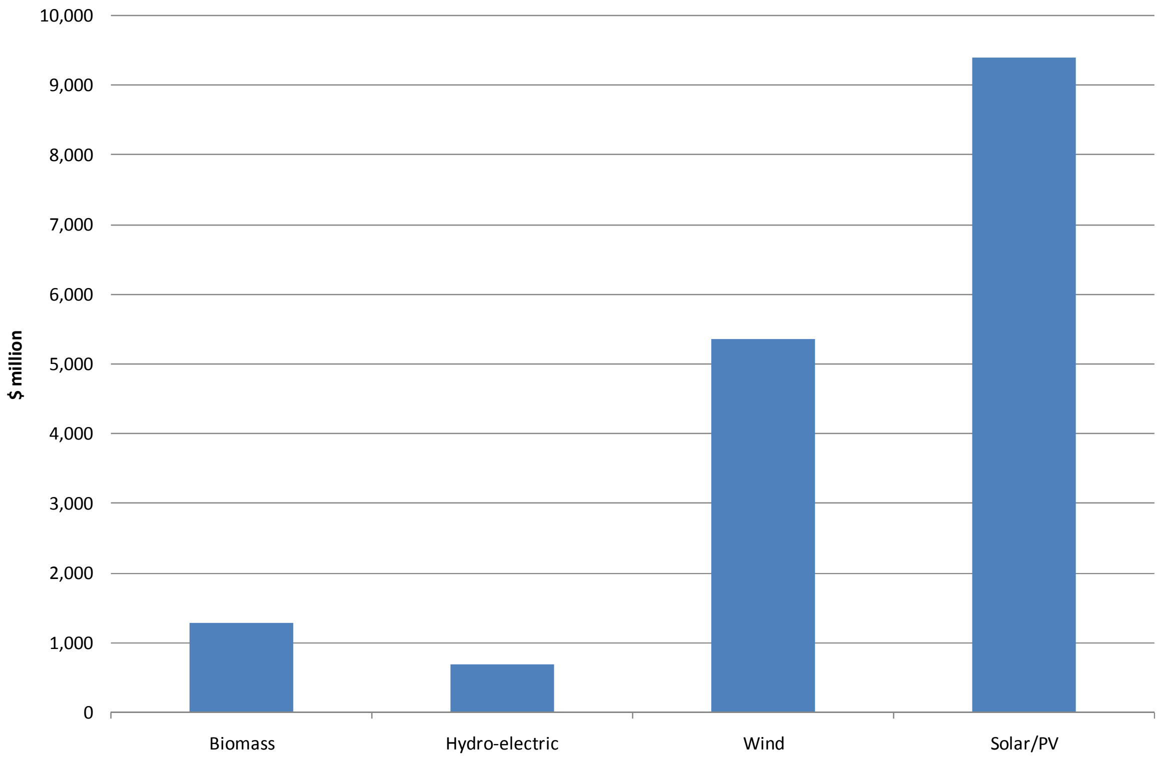
The RET has acted as a spur to investment in renewable generation. Around 3,500 MW of new renewable energy capacity (including expansions at existing hydro-electric facilities) has been commissioned since 2001, with around two-thirds being in wind. Another 1,800 MW, mostly wind generation capacity, is under construction.

Total investments to date have amounted to around $18 billion[14], including investments in small scale systems (see Figure 17). Another $3.7 billion of projects are currently under construction.

[14] SKM MMA estimate based on data collected from a range of sources.

The bulk of investment has been in solar and wind capacity. Wind farms accounted for around $5.3 billion or nearly a-third of the total investment. Of the investments in large scale systems, wind generation has accounted for around 75% of total investment. Investment in solar generation has also been high at around $9.2 billion, nearly all in small scale roof-top systems on homes, school buildings and some commercial buildings.

- **Figure 17: Investment in renewable energy generation from 2001 to 2011**



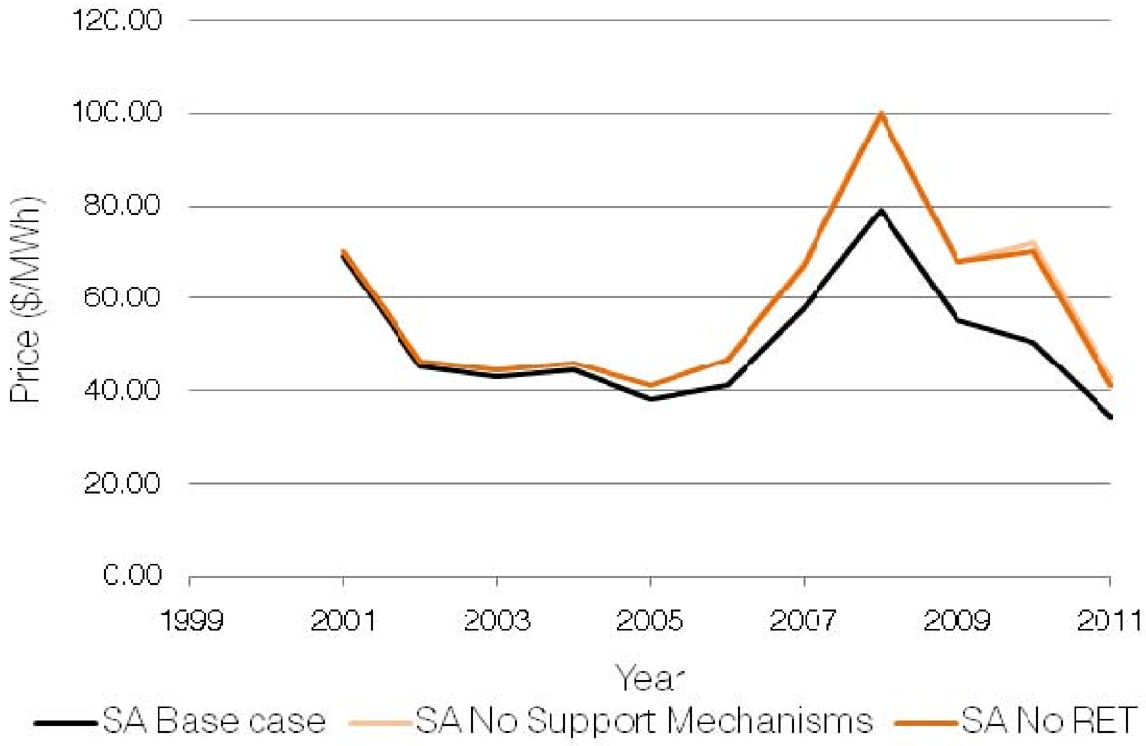
4.4. Electricity Market Impacts

4.4.1. Prices

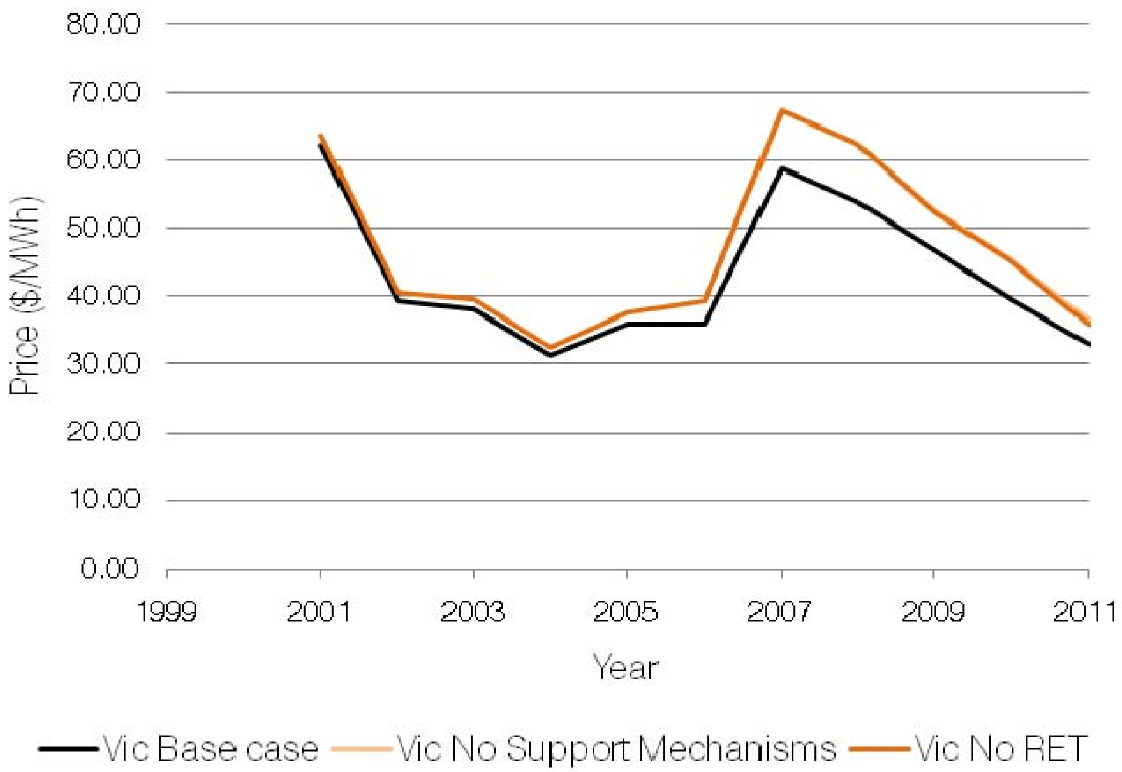
The back casting analysis results showing the impact on wholesale prices are illustrated in Figure 18 to Figure 20 for South Australia, New South Wales and Victoria. For most regions, prices are higher without a RET and the RET contributes the most in terms of price reduction compared to other support mechanisms (i.e. FiT, etc). In Victoria and South Australia, wholesale prices averaged around $4/MWh lower as a result of the RET scheme. The bulk of the lower prices occurred in the last 3 years when electricity demand fell at the same time as new wind capacity was entering the market, leading to downward pressure on prices.

Prices are not much different in NSW, with only a $2/MWh reduction due to the RET scheme. The low impact in the State mainly reflects the low level of additional renewable energy capacity in that State and the fact that NSW generators tend to be price setters in the NEM market.

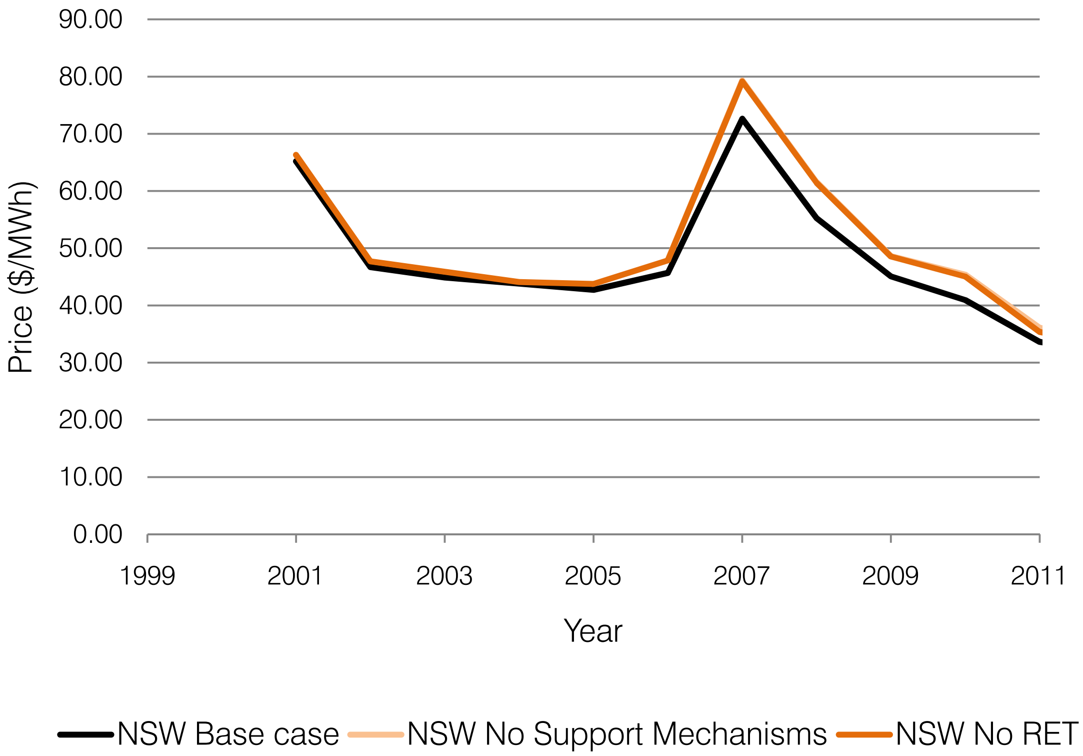
- **Figure 18: Wholesale prices in the South Australian region**



- **Figure 19: Wholesale prices in the Victorian region**



▪ **Figure 20: Wholesale prices in the New South Wales region**



These outcomes are replicated across other jurisdictions and the magnitude of the change is related to the magnitude of renewable energy generation introduced over the period considered. The overall outcome of the modelling indicates that the RET has depressed prices by potentially as much as $10/MWh in particular regions under various supply and demand scenarios. The more extreme the demand supply situation (i.e. tightening), the more likely the impact of no RET would be greater. This is reflected in the prices from 2007 to 2009 being higher in the No RET or No support mechanism case. The difference reduces in 2011 as the supply demand situation eases in the NEM.

The greatest changes would have occurred in South Australia due to the amount of wind that has been built directly linked to the RET scheme. This is depicted in the following table.

- **Table 2: Change in wholesale prices due to the impact of the RET scheme, $/MWh[15]**

Region	With No RET		No RET or other renewable energy policies		Net change in 2012
	Average price change	2012 price change	Average price change	2012 price change	
South Australia	4.37	6.36	4.85	7.85	1.49
Tasmania	6.12	2.75	6.52	3.32	0.58
Victoria	3.67	2.87	3.84	3.43	0.56
NSW	2.51	1.41	2.69	1.95	0.54
Queensland	1.78	0.74	1.96	1.40	0.66

Source: SKM MMA analysis

While the change in NSW is relatively small compared to other regions, it is worth noting that the proportion of the change is relatively high in 2012 which is expected to be driven by the large PV/Solar development that occurred driven by a mix of the FiT scheme and RET scheme.

For the Tasmanian region, it is possible that average price impact is overstated, considering the drought period during this period (i.e. Tasmania results from 2006 to 2012 are dominated by the drought and low inflows). It could be expected that wholesale prices without the additional renewable energy would be higher. But the estimated magnitude may be overstated, since the impact would have been inflated due to low rainfall conditions.

Retail prices have decreased slightly as a result of the RET with the average change since inception estimated to be -$0.63/MWh to -$4.41/MWh. The costs of purchasing certificates have averaged around $0.06/MWh in 2001 to $3.13/MWh in 2012. These costs partly outweigh the decreases in wholesale price, but overall a slight reduction in prices has occurred.

- **Table 3: Change in retail prices due to the impact of the RET scheme, $/MWh**

Region	Average price change	2012 price change
South Australia	-3.22	-3.23
Tasmania	-4.41	0.38
Victoria	-2.52	0.25
NSW	-1.35	1.72
Queensland	-0.63	2.38

Source: SKM MMA analysis

4.4.2. Fossil fuel impacts

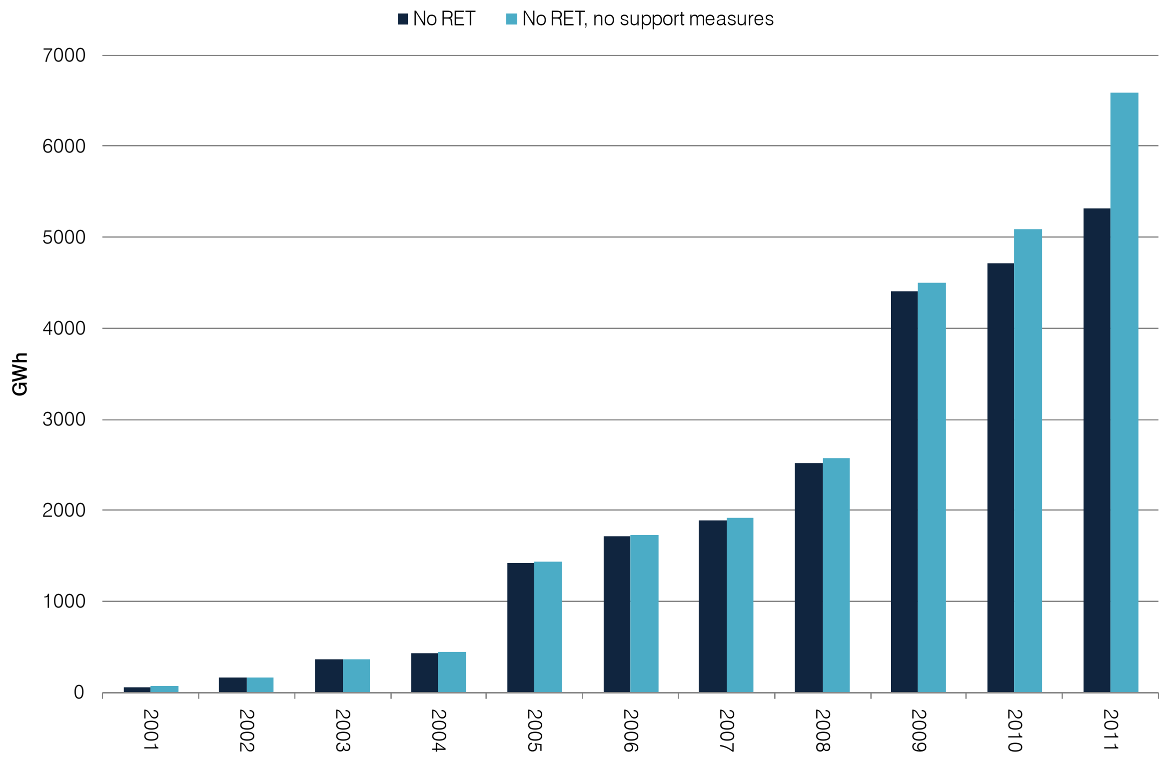
The RET and other renewable energy support mechanisms have reduced the level of fossil fuel generation across the various regions modelled. This is depicted in Figure 21.

[15] Note the values in this table are positive which represents higher prices in the cases of No RET or No RET or other renewable energy support policies

In terms of thermal generation the modelling suggests a 1.7% decrease over the 2001 to 2012 historical period for the NEM, with a subsequent reduction in 2012 of approximately 4.7%. Of this only 0.16% is attributable to other support schemes with the majority aligned to the renewable developments driven by the RET. Although by 2012 the proportion of displacement of thermal generation attributable to other schemes would have been greater (i.e. 0.9% of the 4.7%), due to the large amount of Solar developed under FiT schemes in the various regions.

Around 70% of the reduction has been in coal-fired generation, with a further 30% from gas-fired generation. The level of displacement of gas fired generation would have been greater were it not for other policies supporting this form of generation

- **Figure 21: Annual incremental changes in thermal generation**



5. Future Impacts

5.1. Small Scale Renewable Energy Generation

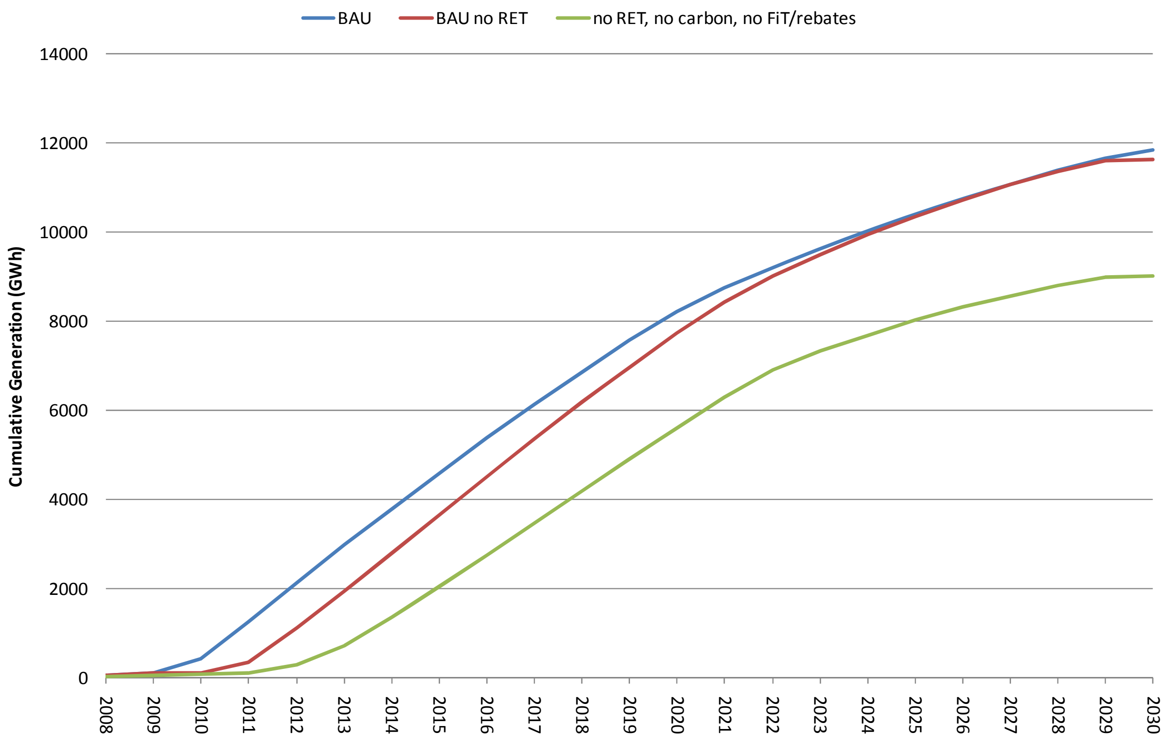
Small scale generation includes rooftop solar systems. The SRES and the MRET scheme before that provide a range of upfront incentives that reduce the installation cost of these systems.

Projected small scale PV generation as a result of the RET scheme is shown in Figure 22. With the RET scheme (and assuming other support measures continue as planned), the level of generation from small scale PV is projected to increase from around 1,300 GWh in 2011 to around 8,200 GWh in 2020.

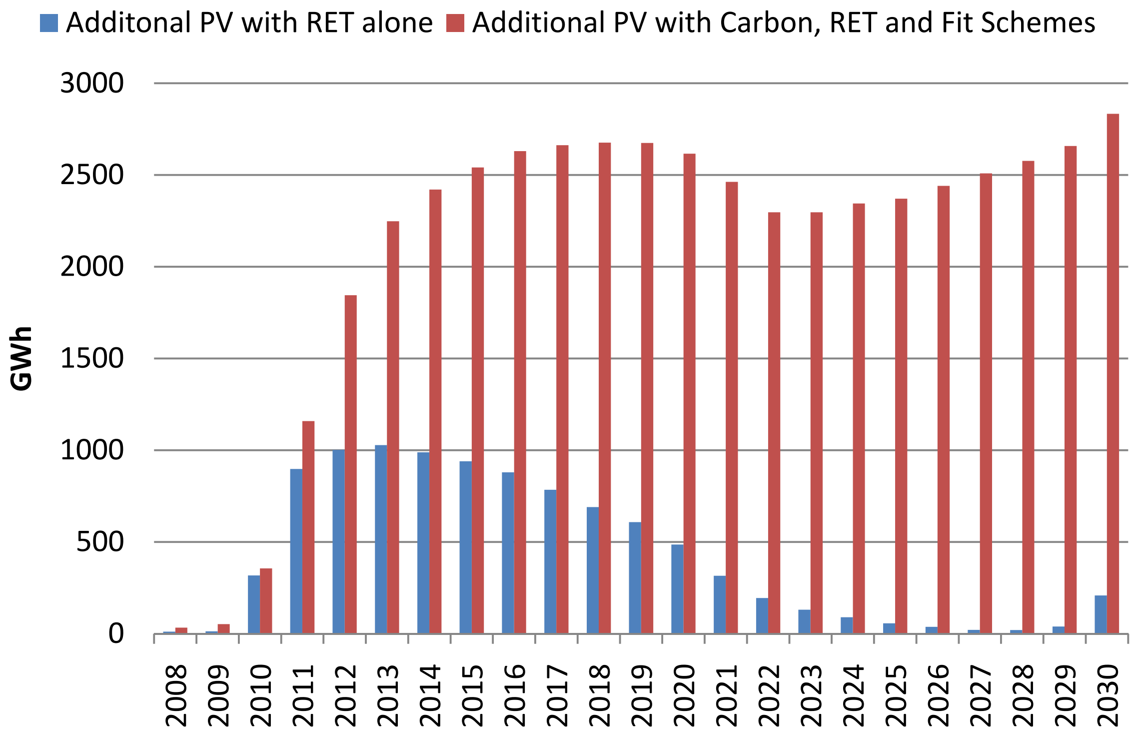
The analysis provides insights into the key drivers for the projected uptake:

- In the short term, the level of payment provided under the SRES (through the multiplier arrangements) is a major driver. As can be seen in Figure 23, a large proportion of uptake in the period 2011 to 2013 occurs under the SRES scheme, providing evidence of its impact on uptake.
- In the long term, uptake is driven by the continuing decline in system costs and rising retail prices as a result of carbon pricing and ongoing increases in network costs.

Figure 22: Projected generation from small scale PV



▪ **Figure 23: Impact of RET scheme on small scale PV generation**



The analysis indicates that the SRES scheme has brought forward the purchase of small scale PV systems. The bigger impact has been through the feed-in tariff arrangements, as the analysis indicates that without the SRES scheme uptake would still have been strong by 2015, with installed capacity being only 600 MW or 20% less without the payments under the SRES scheme. Even without the premium feed-in tariff payments, strong uptake is predicted, reaching around 1,380 MW by 2015 or about 60% of the level with only FiT payments and 45% of the level with the SRES and FiT payments.

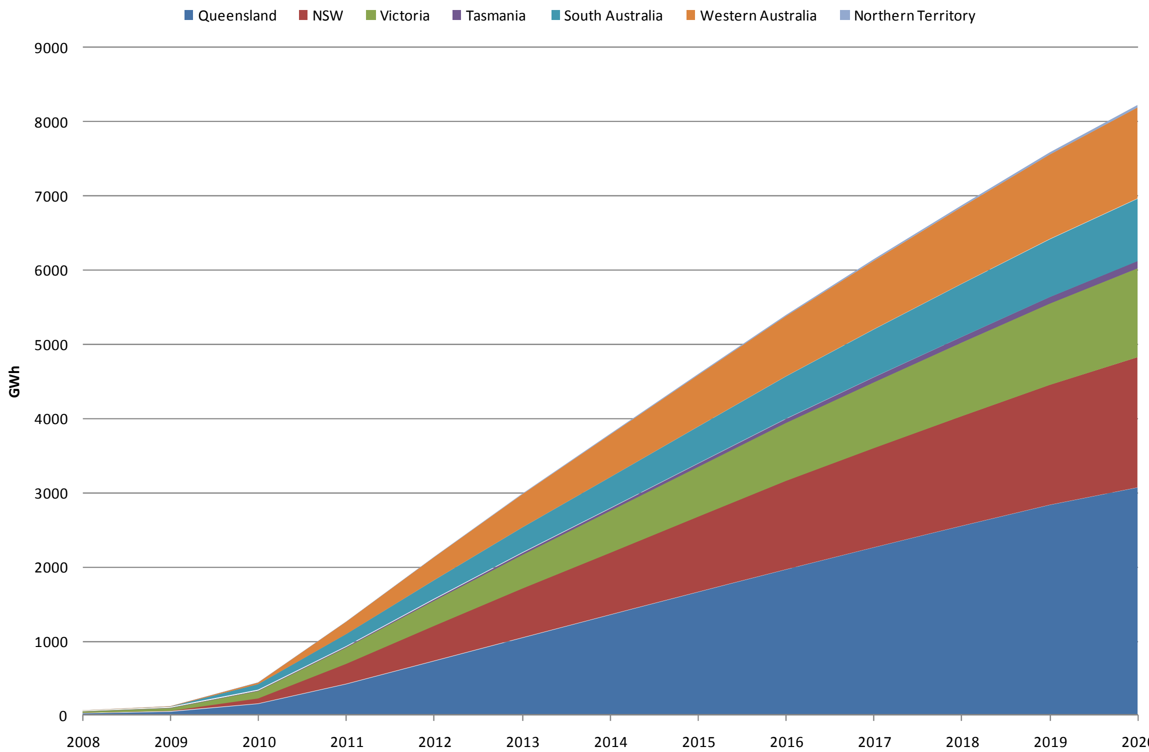
▪ **Table 4: Installed capacity and investment in small scale PV systems**

	Up to 2010		2011 to 2015		2016 to 2020	
	Installed capacity, MW	Investment $M	Installed capacity, MW	Investment, $M	Installed capacity, MW	Investment, $M
RET and FiT	335	2516	3084	14884	5216	21172
No RET	94	703	2453	11320	4908	19583
No RET, No FiT	65	485	1378	6394	3557	13794

Investment in PV systems has amounted to around $2.5 billion by the end of 2010 and is projected to reach around $14.9 billion by the end of 2015.

Queensland and NSW are the States with the greatest level of uptake, reflecting the higher insolation levels and favourable FiT premiums.

Figure 24: Generation by solar PV systems by State



Even though the projected volume of SRES generation is much larger than first anticipated, this does not necessarily translate into an equal relative increase to scheme cost. Rather costs are going to be less because of lower installed costs, reduced level of support as multipliers and other support measures are reduced, and the countervailing impact of lower wholesale prices.

5.2. Large Scale Renewable Energy Generation

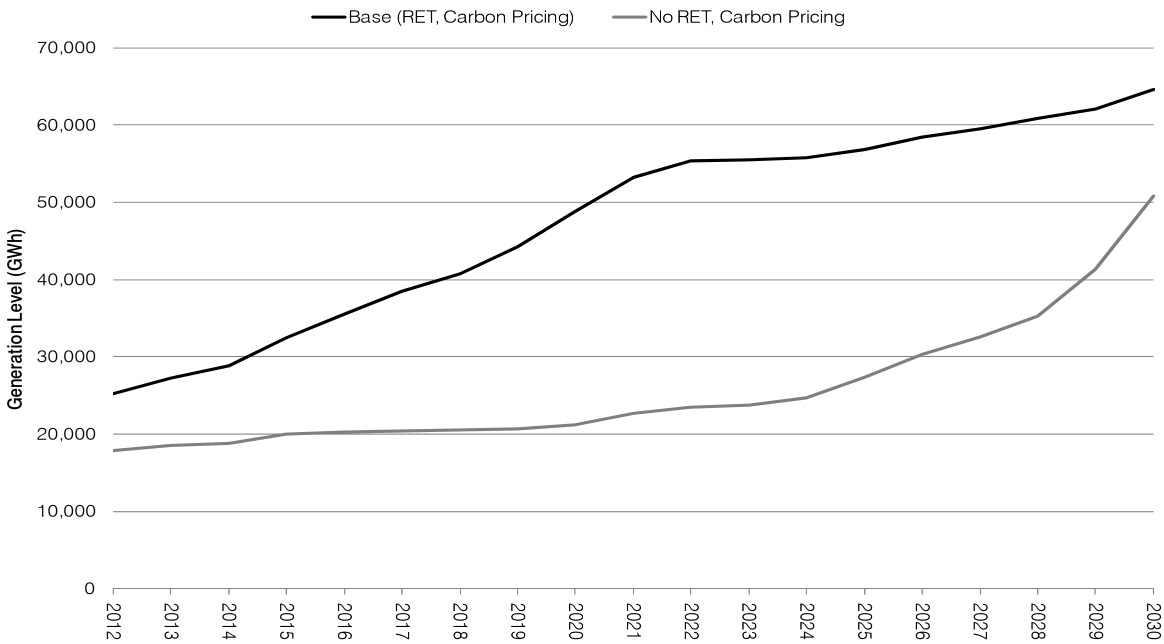
The RET scheme is a major driver of investment in large-scale generation over the next decade (see Figure 25). With only carbon pricing, the level of renewable energy generation is expected to have grown by only 5,000 GWh by 2020, mostly through investment in low cost hydro-electric upgrades and some biomass based projects in response to higher electricity prices under carbon pricing and incentives under the Green Power program. Investment in solar generation under the Solar Flagships programs would add to the level of generation[16].

One impact of the RET scheme is to change the mix of renewable energy generation away from a mix dominated by hydro-electric generation to contributions from a wide range of technologies.

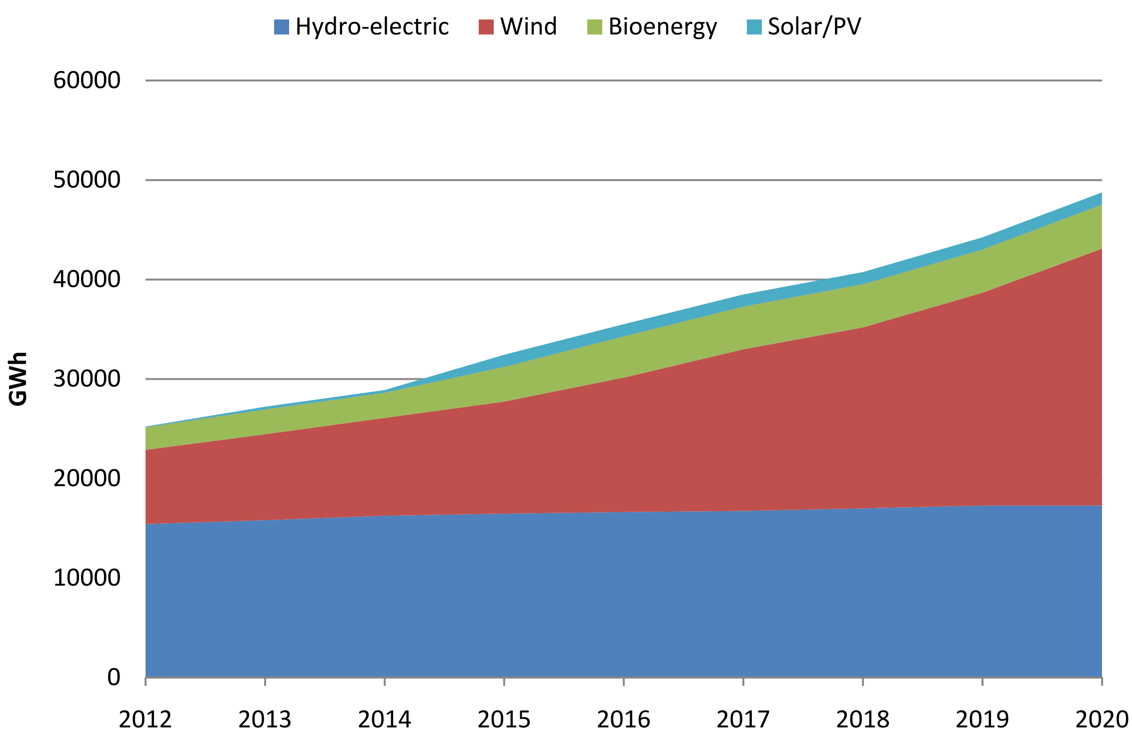
Most of the additional capacity is wind generation, with this technology projected to be the largest source of renewable energy generation by 2020, comprising just over half of the total renewable energy generation and around 10% of total generation (see Figure 26). Hydro-electric generation is projected to be around 12% higher as a result of the RET and carbon pricing mainly through upgrades of existing systems. However, this form of generation is expected to comprise around 35% of total renewable energy generation by 2020, compared with over 60% in 2011.

[16] Solar Flagships was assumed to proceed under the no RET scenarios. However, the CEFC was not assumed in these scenarios.

■ **Figure 25: Projected renewable energy generation**



■ **Figure 26: Renewable energy generation by technology, with RET and carbon pricing**



The rapid growth of renewable energy generation comes at the expense of fossil fuel generation, mainly coal fired generation (see Table 5). Gas fired generation is projected to increase over the next decade despite projected rising gas prices but its proportion of total generation decreases. Coal-fired generation is projected to fall mainly due to retirements of high emission plant under the carbon pricing mechanism.

- **Table 5: Projected electricity generation by fuel type, GWh**

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	168020	161442	161972	161565	159886	158595	158701	157806	156162
Gas	40781	42552	41517	42590	45039	45000	44939	43969	43413
Hydro	15417	15795	16260	16456	16619	16733	16986	17285	17285
Other renewable energy	9799	11425	12631	15981	18897	21763	23760	26958	31471

Source: SKM MMA analysis

An extra 7,000 MW of new renewable energy capacity will be required to meet the target (above what has already been committed). The largest portion of this investment will go to the south and south eastern regions (see Table 6) due to the good wind resources in these regions and a better ability to absorb high levels of wind penetration (as opposed to Western Australia which also has a good wind resource). It has been assumed that existing planning policies remain unchanged in the future for this analysis.

- **Table 6: Projected capacity additions and investment in renewable energy by State, RET and carbon pricing scenario**

State	to 2015		2016 to 2020		2021 to 2030	
	MW	$M	MW	$M	MW	$M
Queensland	337	1124	14	44	1668	4976
NSW	182	428	1422	3245	548	1155
Victoria	298	701	1292	2950	1296	2729
Tasmania	319	751	844	1926	0	0
South Australia	563	1325	1490	3402	794	1672
Western Australia	363	853	446	1018	162	341
Northern Territory	0	0	0	0	200	421

The net present value of investment (using a discount rate of 6% per annum) in renewable generation is estimated to be:

- $13.8 billion for the period from 2012 to 2020. Of this, around $2.1 billion would have occurred with carbon pricing alone.
- $18.7 billion for the period from 2012 to 2030. Of this around $9.9 billion would have occurred with carbon pricing alone.

The analysis indicates that investment in large scale renewable energy generation in the period to 2020 is largely driven by the RET, but that after 2020 (particularly after around 2025) the carbon pricing scheme is likely to act as the major spur for investment. In this sense, the RET scheme can be seen to be complementary to the carbon pricing scheme in that the RET is driving investment until the carbon price takes over as the main driver for investment sometime after 2020.

5.3. Electricity Market Impacts

5.3.1. Grid based electricity demand

Electricity demand is impacted by a number of factors including income, price, industrial growth and trends to purchase electronic goods. Over the last few years electricity demand growth has slowed. Increasing network fees, the phasing out of manufacturing and other industrial loads and high electricity tariffs are some of the influences affecting demand. In addition, the RET scheme may have impacted on electricity demand through the uptake of small scale systems such as hot water solar panels and small scale PV systems, leading to a reduction in grid based demand.

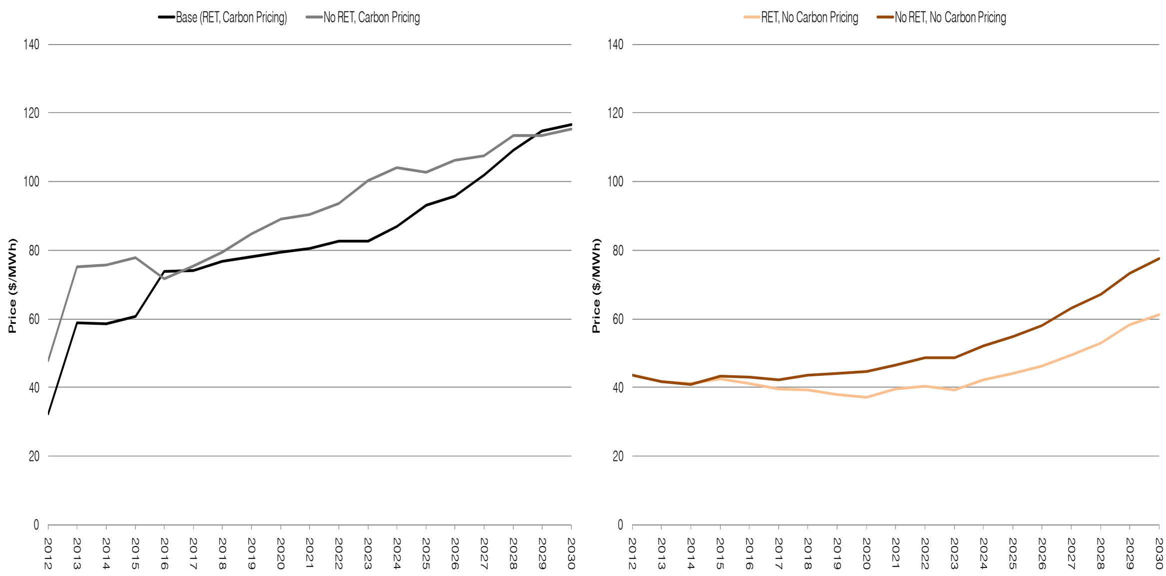
5.3.2. Wholesale prices

The potential impact of the RET scheme on wholesale pricing is ambiguous on an *a priori* basis. The low marginal cost of renewable generation would put downward pressure on prices during periods of rapid uptake and high penetration. This impact would be exacerbated if the level of uptake occurred at a faster pace than growth in demand, causing a capacity surplus in the market. On the other hand, the need for new fossil fuel plant to meet load growth would eventually see prices return to long run marginal cost levels.

The analysis indicates that the RET scheme will likely lead to lower wholesale prices (see Figure 27). Under carbon pricing, the average price difference is around $9/MWh or a 10% reduction. Without carbon price, the average price difference is around $6/MWh or a 14% reduction.

- **Figure 27: Projected impact of RET on wholesale prices**

(a) With carbon (b) Without carbon



However, the results should be treated with caution. The impact is mainly driven by the projected slow rate of growth in demand during the projection period, resulting in a high level of capacity relative to demand. The addition of renewable energy capacity to meet the target exacerbates this level of surplus of capacity. In the case of carbon pricing, the impact is ameliorated by the retirement of some fossil fuel generation due to it being no longer economic. Early retirement does not occur under the assumptions used in this analysis in the no carbon scenario, but it is possible that some

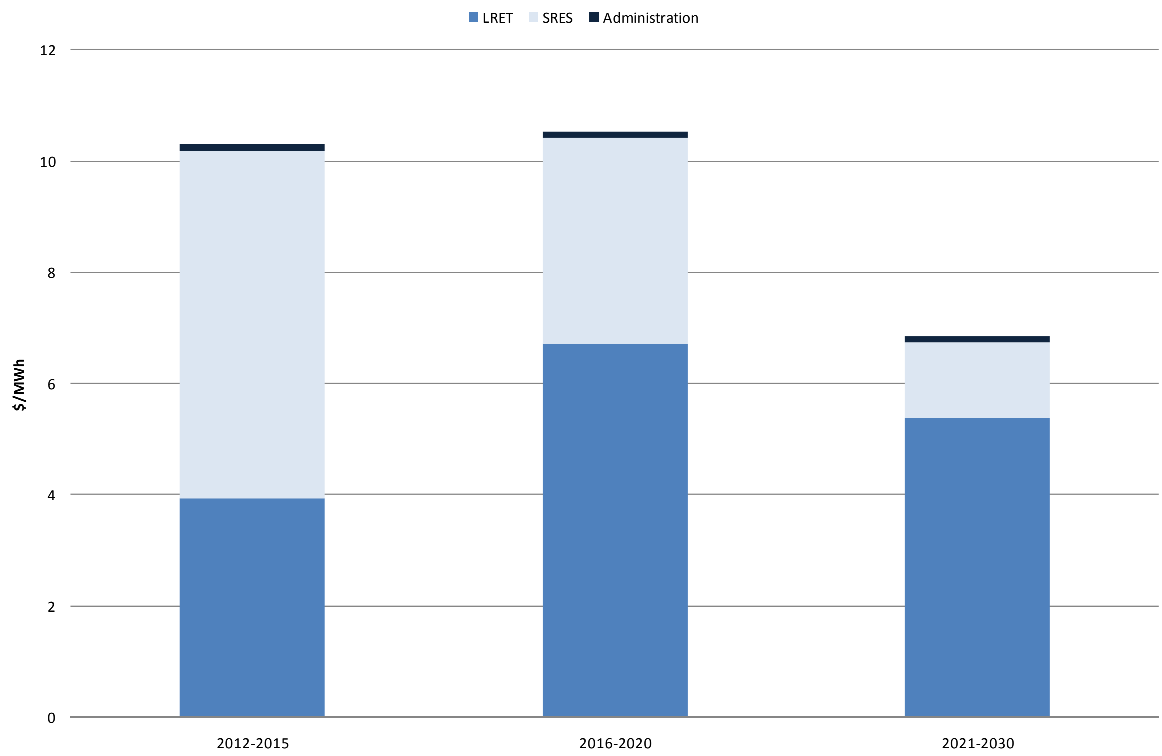
generators may shut down plant to improve the overall profitability of their portfolio. This factor has not been taken into account in the analysis.

5.3.3. Retail prices

The impact on retail prices will depend on the net outcome from the impact on wholesale prices and the additional compliance costs from meeting liabilities under the RET. The latter is equal to the certificate price times the number of certificates generated (under LRET and SRES) plus administration costs divided over the liable load.

The estimated compliance costs are shown in Figure 28. Compliance costs are expected to average around \$6.9/MWh to \$10.5/MWh. Over the period to 2015, the LRET scheme is expected to contribute around \$4/MWh whilst the SRES scheme is expected to contribute around \$6/MWh (see Figure 28). After 2015, the relative contribution of the LRET scheme increases as the target is ramped up, contributing around \$7/MWh in the period from 2016 to 2020 and \$5/MWh in the period from 2021 to 2030. The contribution of the SRES scheme falls over time as the certificate price falls and as the multiplier provision expires.

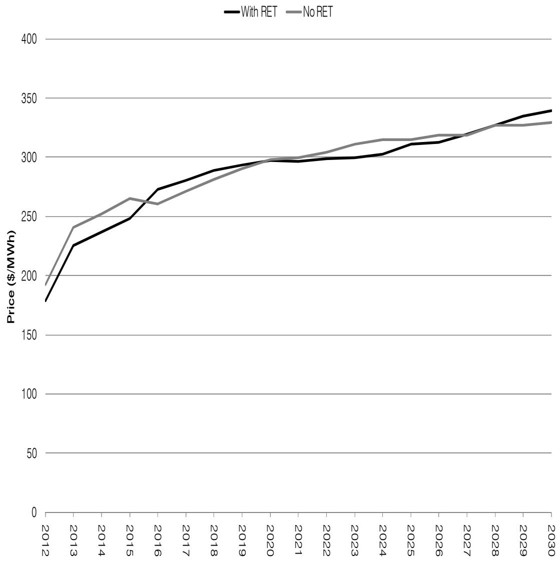
- **Figure 28: Average compliance costs of the RET with carbon pricing**



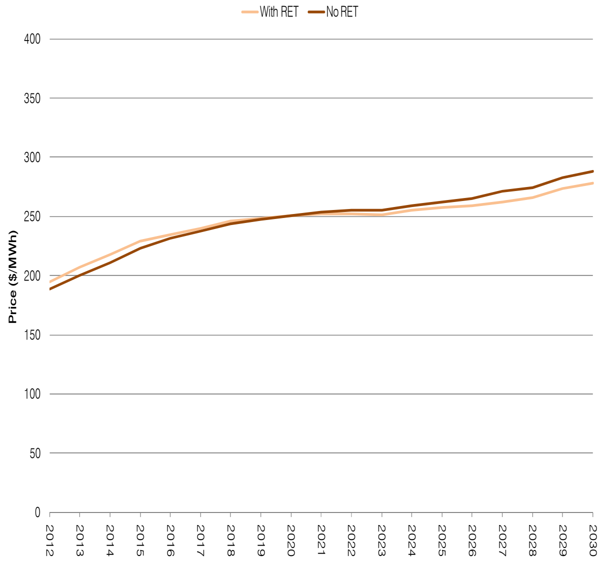
The impact of retail prices for residential customers is shown Figure 29. On average there is a small decrease in the retail price of around \$3/MWh with carbon pricing and \$1/MWh without carbon pricing. Excluding some large wholesale price reductions in the period to 2015 in the carbon pricing scenario, there is a small increase in retail tariffs of around \$1/MWh over the period from 2016 to 2030, an increase of around 0.5%.

Figure 29: Impact of RET on residential electricity tariffs, NSW

(a) With Carbon price



(b) Without carbon pricing



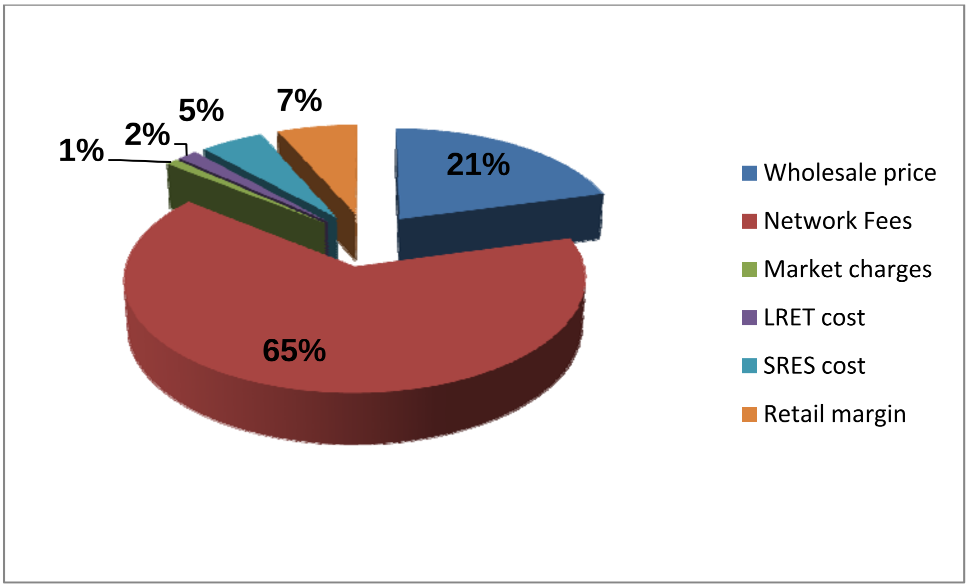
Assuming the wholesale price decrease is not passed through then the retail price increase is on average around $9.20/MWh with carbon pricing and around $11.00/MWh without carbon pricing. This represents around 3% and 4%, respectively, of retail tariffs over the projection period.

Electricity tariffs have increased sharply over the last 5 years and are expected to increase in the near future as a result of carbon pricing and increasing network fees. This has focussed debate on drivers of the increase in costs.

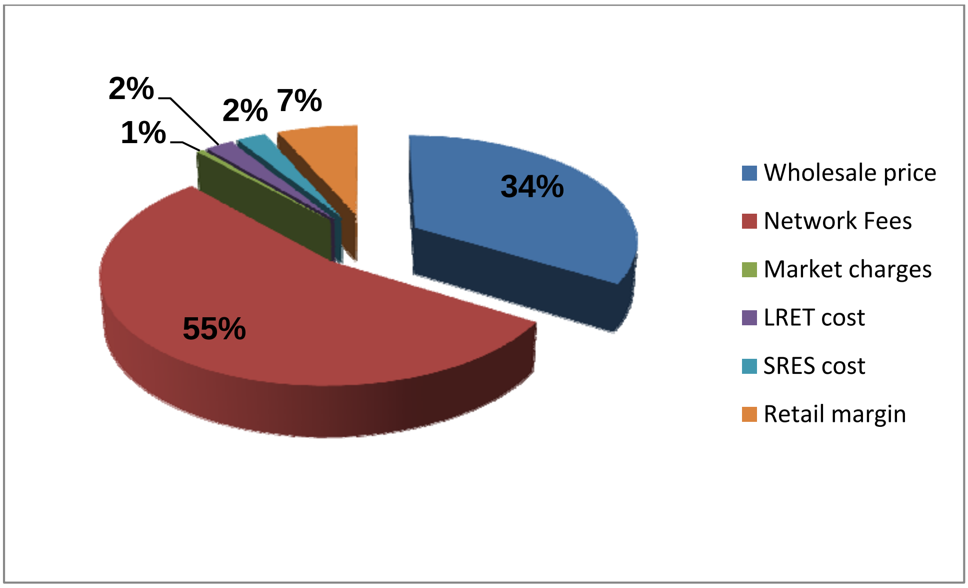
The components and impact on electricity tariffs are shown in Figure 32 (note NSW shown by way of example). As can be seen the largest proportion and influence on electricity tariff are the wholesale prices and network fee components making up over 85% of the total electricity tariff. The proportion of the tariff attributable to the compliance costs[17] of the RET scheme is around 7% in 2012 In addition, wholesale prices and network fees (if existing cost trends continue) are projected to increase. However, the contribution from the RET scheme costs are expected to fall over time from 7% in 2012 to around 5% in 2020 and 2% in 2030. This is illustrated in Figure 30 and Figure 31 for 2012 and 2020 respectively.

[17] The compliance cost of the RET scheme will be passed on to end-users.

- **Figure 30 Components of NSW Retail Tariffs for 2012**



- **Figure 31 Components of NSW Retail Tariffs for 2020**



The actual contribution of the RET scheme to retail tariffs is less than portrayed in this analysis:

- As discussed in Section 5, the RET scheme will act to put downward pressure on prices. Without the RET, tariffs are still likely to continue to increase with more of the cost burden from wholesale price changes.
- The analysis behind Figure 32 to Figure 34 assumes network tariffs do not increase in real terms beyond current regulatory periods. This may be seen as a conservative assumption, especially if peak demand continues to grow at a more rapid rate than average demand.
- The analysis does not take into account the cost of the FiT schemes operating at a State level. These costs will likely be borne even in the absence of the SRES scheme as the FiT have provided a greater incentive for uptake.

Figure 32: Retail tariff components, NSW residential customers, with RET and carbon pricing

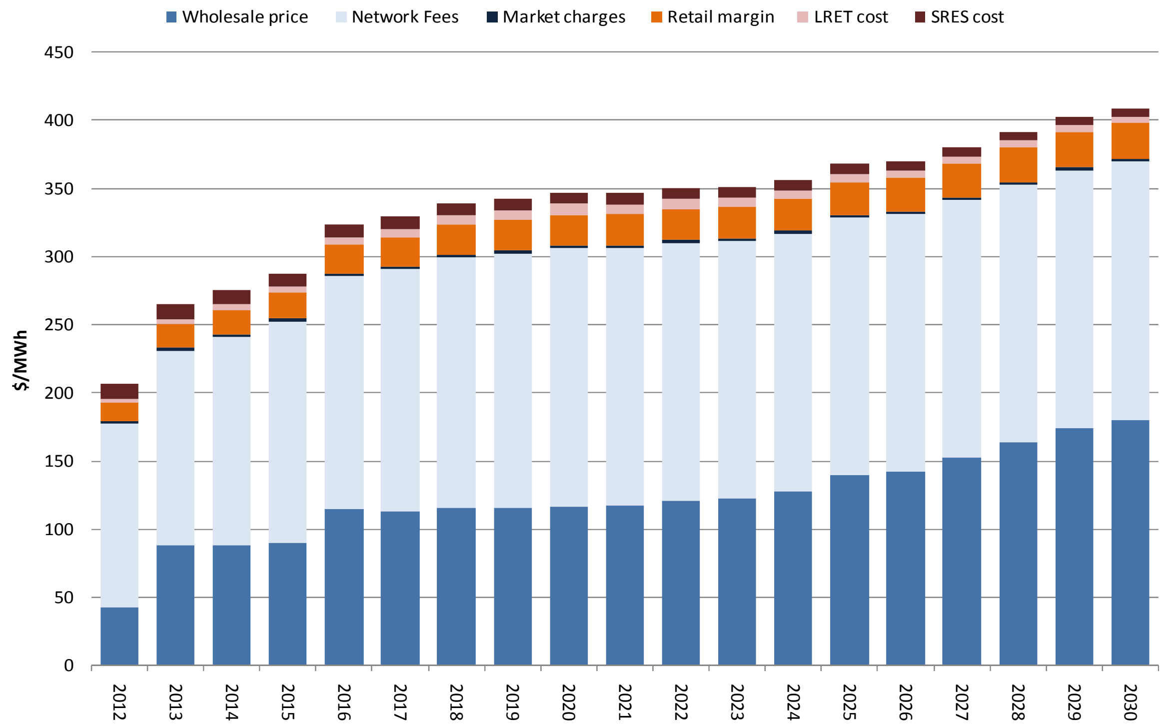
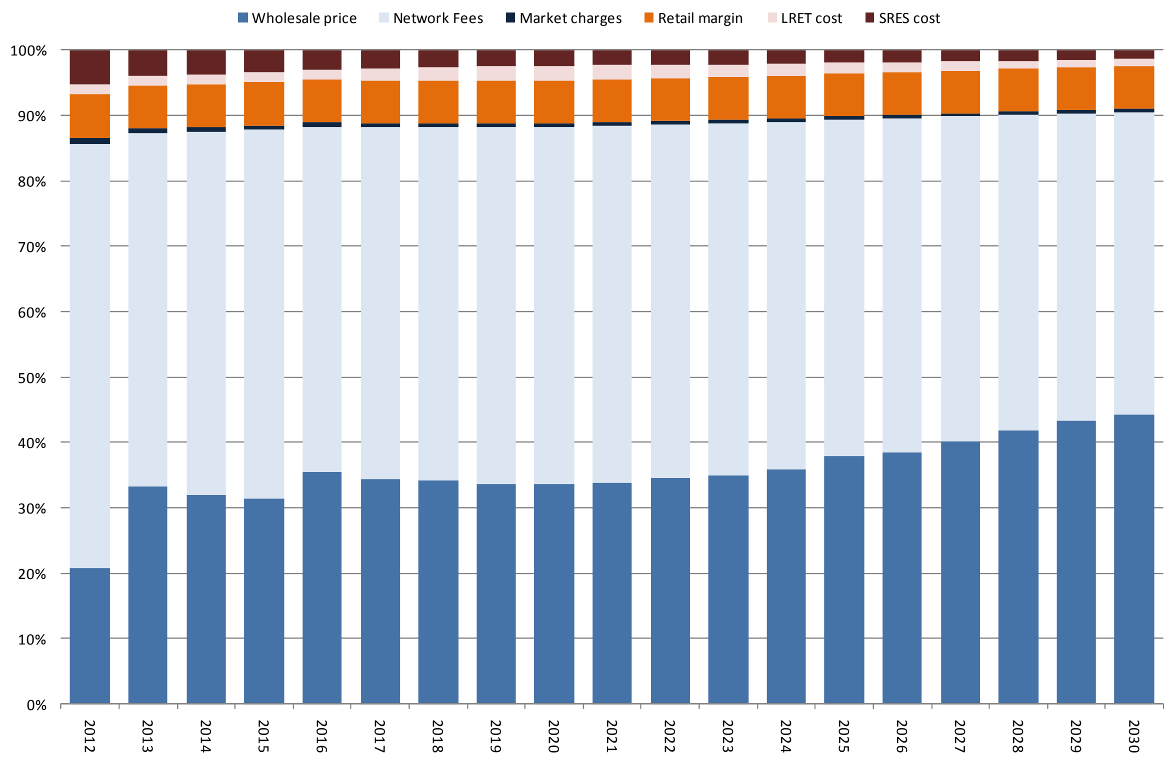
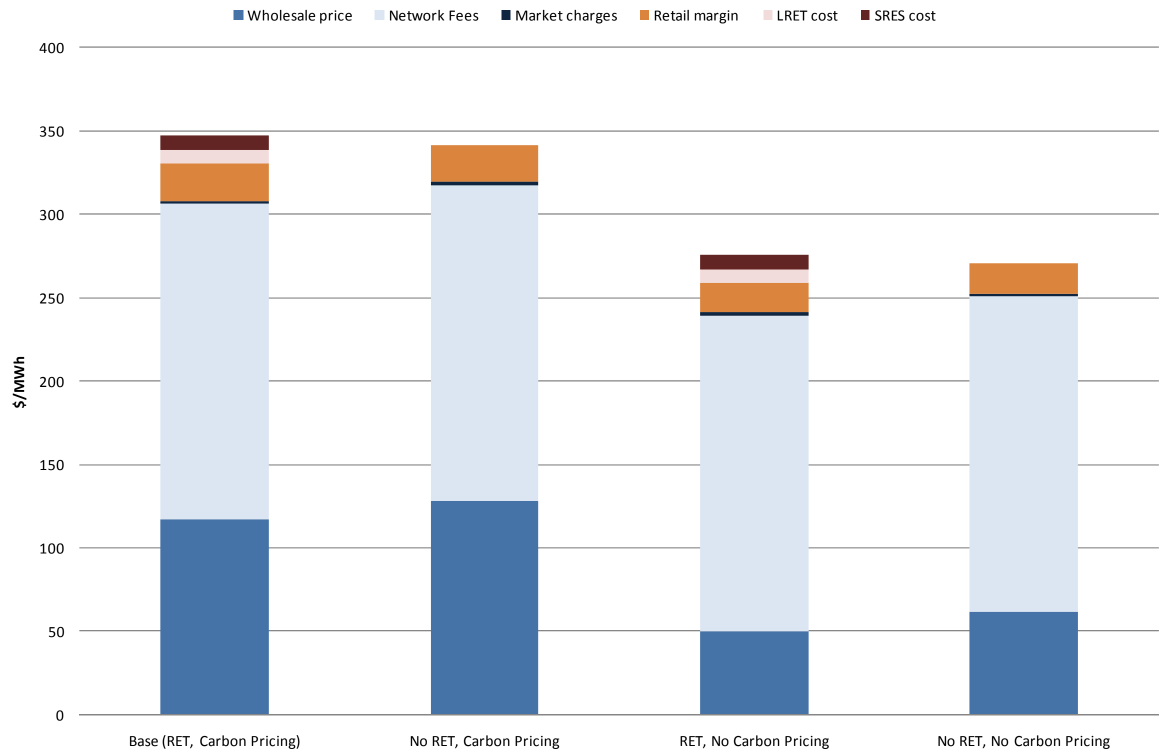


Figure 33: Percentage contribution of LRET and SRES on electricity tariffs with carbon pricing



■ **Figure 34: Comparison of tariff rates across the scenarios**



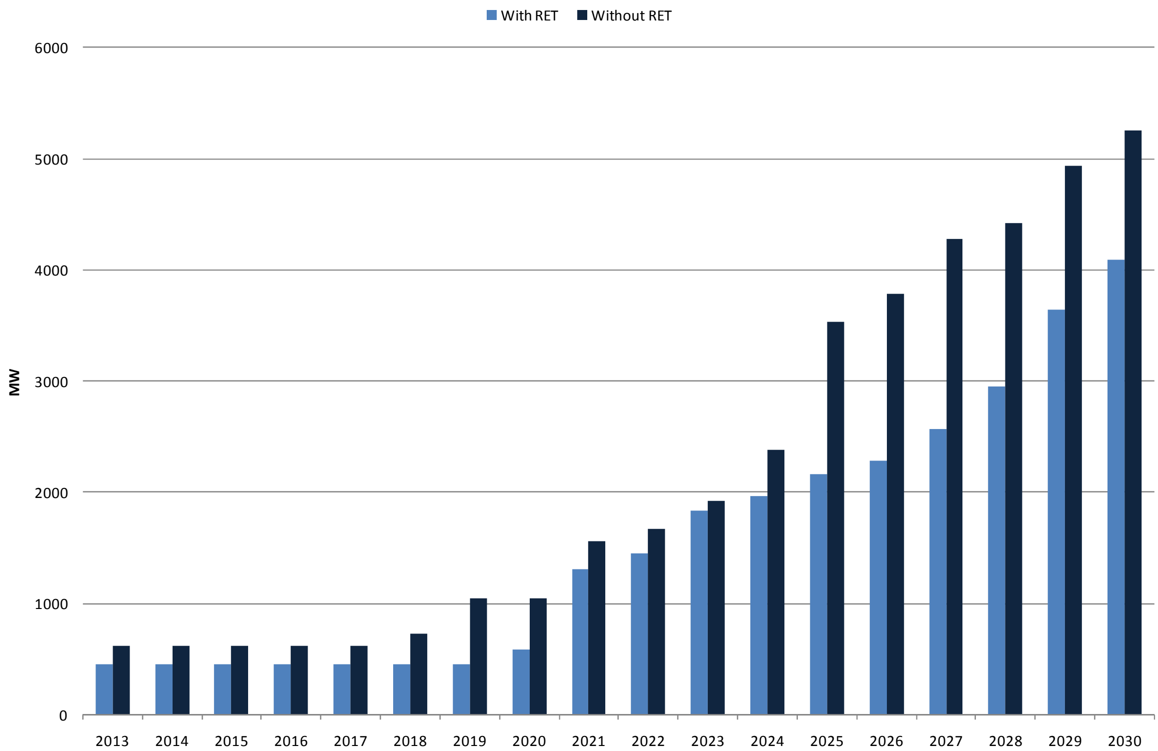
5.3.4.Investment in generation

Uptake of renewable energy generation will lead to a displacement of fossil fuel generation and this will be reflected in reduced investment in new fossil fuel generation. There is no investment in new coal plant forecast in the period to 2030 with carbon pricing even without the RET. Around 600 MW of mostly open cycle plant is required in the period to 2020 and around 3,500 MW of gas fired open cycle and combined cycle capacity in the period from 2021 to 2030 with the RET scheme. Without the RET scheme, around 1,000 MW of new gas plant is required by 2020, and around 4,200 MW from 2021 to 2030. Thus the difference in capacity required is around 1,100 MW more gas plant without the RET scheme in operation.

On a generation basis, the level of both coal and gas based generation falls as a result of the RET (see Figure 36). Over the period to 2020, coal fired generation is around 7% lower as a result of the additional renewable generation, resulting in a fall in total generation from coal over the period. Gas fired generation is lower by around 9% as a result of the RET, but there is still a small rise in overall generation from gas over this period.

Both coal and gas-fired generation increases slightly over the period from 2021 to 2030 even with a RET scheme. However, gas-fired generation is around 13% lower as a result of the RET scheme whilst coal fired generation is around 12% lower.

Figure 35: New gas capacity required with and without the RET assuming carbon pricing

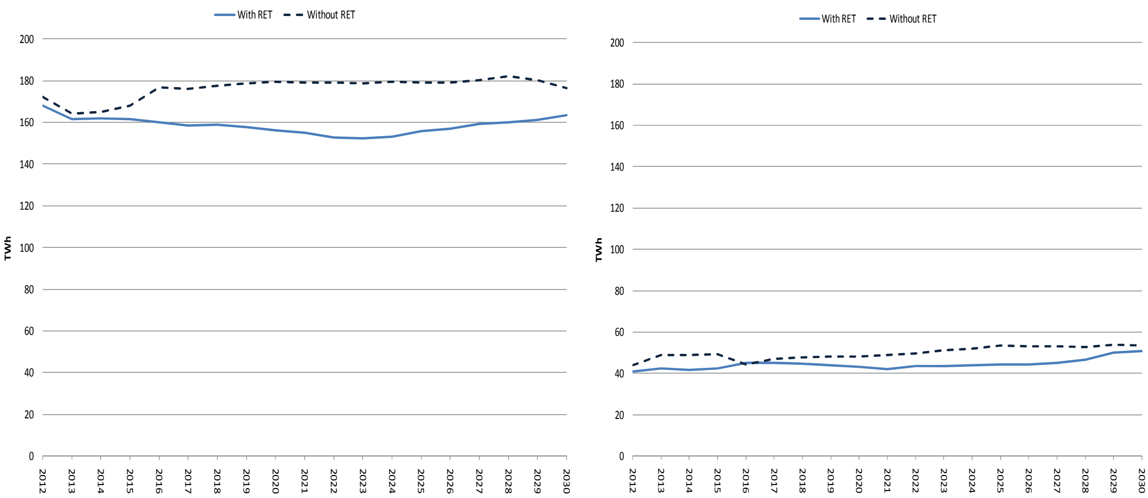


Source: SKM MMA analysis. Note: cumulative new capacity to the year shown.

Figure 36: Impact on coal and natural gas generation, carbon price scenario

(a) Coal

(b) Natural Gas



6. Benefits and Costs

6.1. Emission reductions

Uptake of renewable energy generation provides additional benefits from abating greenhouse gases when there is no carbon pricing scheme. With the carbon pricing mechanism, there is a national cap on emissions, and so a higher level of abatement caused by a complementary policy would satisfy the abatement need in other economic activity in Australia, or more likely reduce the import of permits when Australia is a price taker on world carbon markets.

Projected abatement from the RET scheme is shown in Figure 37. The total level of abatement from renewable generation in the period to 2030 is around 380 Mt CO_2e with carbon pricing and 250 Mt CO_2e without carbon pricing. A higher proportion of this abatement occurs in the period after 2020. The level of abatement is higher for the "with carbon" pricing scenario as the high carbon prices make more coal fired generation marginal in the dispatch order, and the level of renewable generation displaces this coal-fired generation.

Care needs to be taken over interpreting the abatement results for the "with carbon" scenario. The data on abatement should be considered the contribution of the RET scheme to meeting the national emission target. Without the RET scheme, additional permits from other countries would need to be purchased. The cost foregone from not purchasing international permits is around $6.5 billion in present value terms (assuming a 6% discount rate). This is on top of the value to the community of emission abatement to date – for example, 2012 emissions reductions would have a value of around $140 million using a carbon price of $23/t CO_2e.

- **Figure 37: Contribution of the RET to abatement of greenhouse gases**

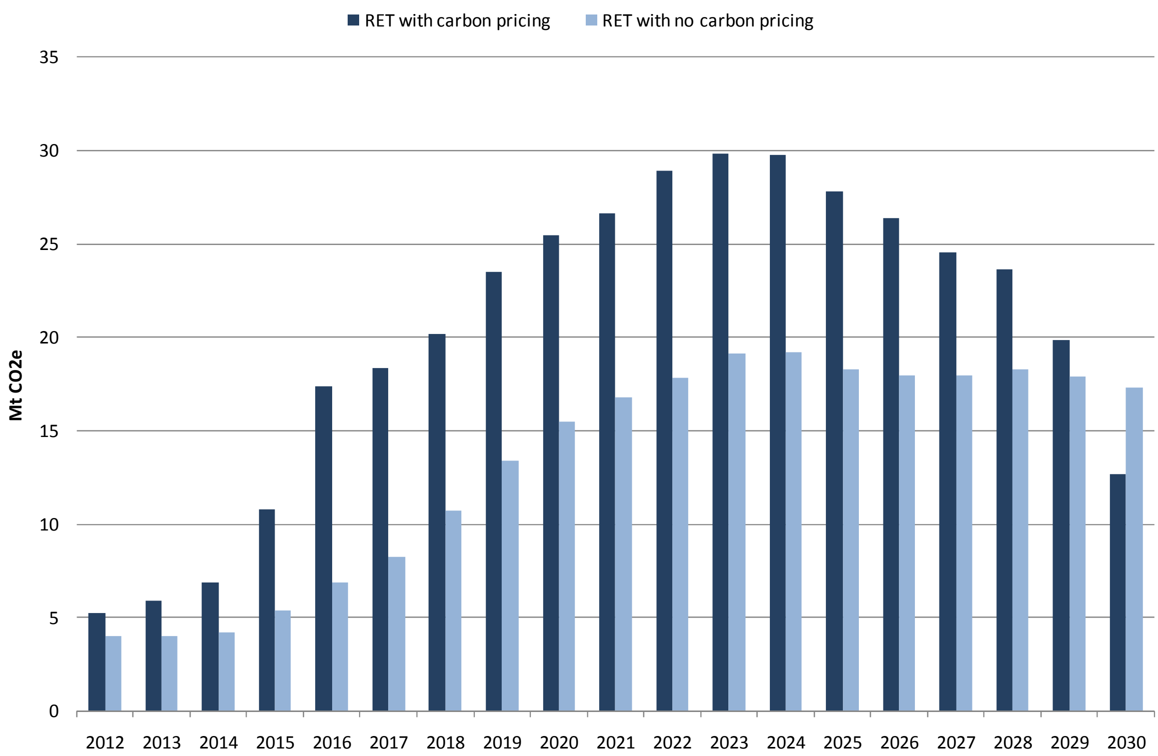


Table 7: Level of abatement by the RET scheme, Mt CO_2e

Carbon pricing:	2012 to 2020		2021 to 2030		2012 to 2030	
	Total	Annual average	Total	Annual average	Total	Annual average
Yes	134	15	250	25	384	20
No	72	8	181	18	253	13

Appendix A Renewable Technology Assumptions

A.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:

- Office of the Renewable Energy Regulator (replaced by the Clean Energy Regulator).
- The LGC Registry.
- 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 8. Not all projects contained in the data base are eligible to earn certificates. For example, only a portion of the generation from the hydro-electric projects is eligible to generate certificates.

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[18], except in

[18] 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.

scenarios were 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 possibly 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).

- **Table 8: 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.

With these restrictions, the available capacity from prospective projects to meet future growth in the target by technology is shown in Table 9. Eligible generation for these projects is shown in Table 10.

The data indicate two 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 wind projects in these States.

Table 9: 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
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 10: 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

Technology	Qld	NSW/ACT	Vic	Tas	SA	WA	NT	Total
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.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.2.1 Capital costs

Current capital costs by technology are shown in Figure 39 to Figure 41. 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 11: 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:

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[19] and Solar Silex's large scale solar concentrator facility in Mildura[20], 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:

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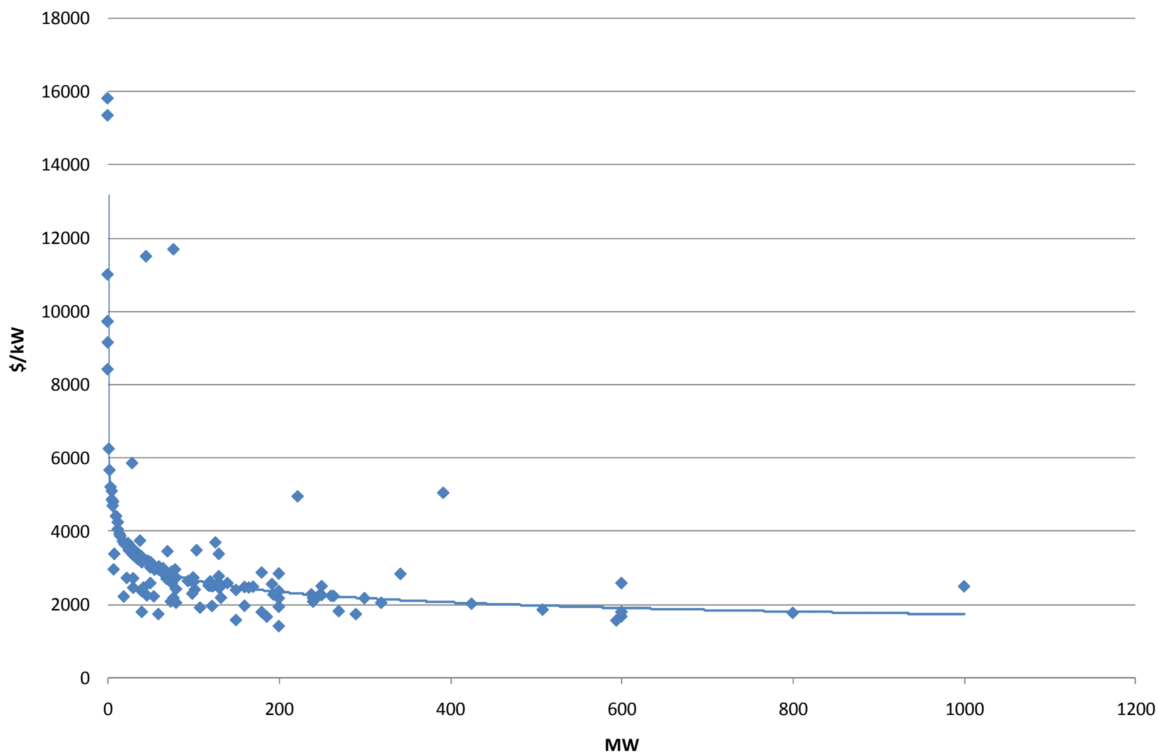
[19] A 40 MW project located, which is to receive $60 million from ARENA should it proceed.

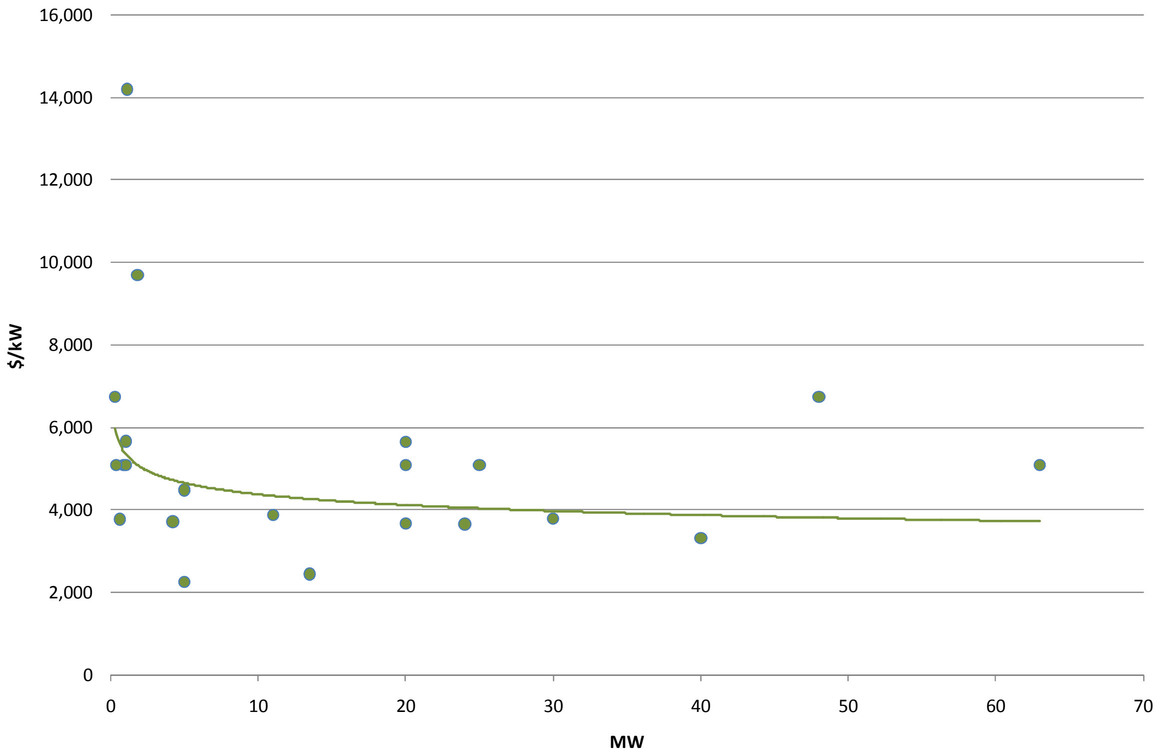
[20] This is a 100 MW project reported to cost around $500 million. The project has been awarded around $125 million in Federal and Victorian funding should it proceed.

- $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).

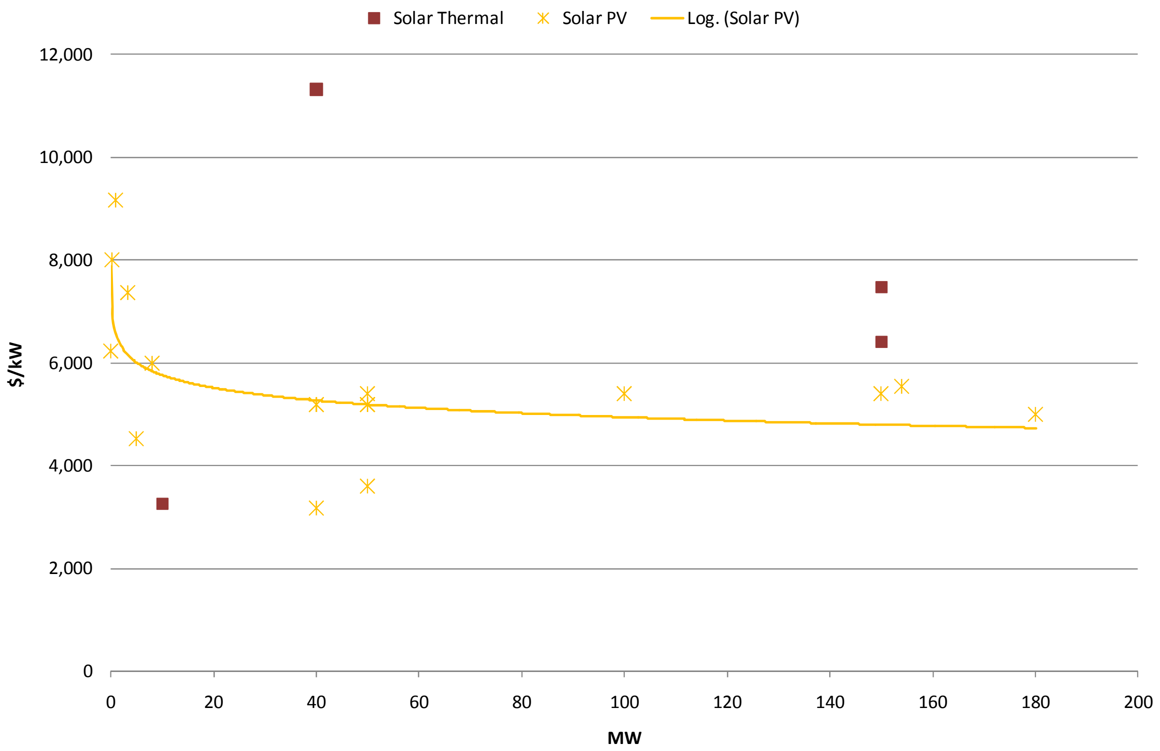
Figure 38: Capital costs for prospective wind projects



- **Figure 39: Capital costs for prospective biomass projects**



- **Figure 40 Capital costs for prospective solar projects**



Source: SKM MMA renewable energy data base

Capital costs vary as a function of capacity, as can be seen from the scatter plots shown above[21]. 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.

Assumed capital cost trends are shown in Figure 41. 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.

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.

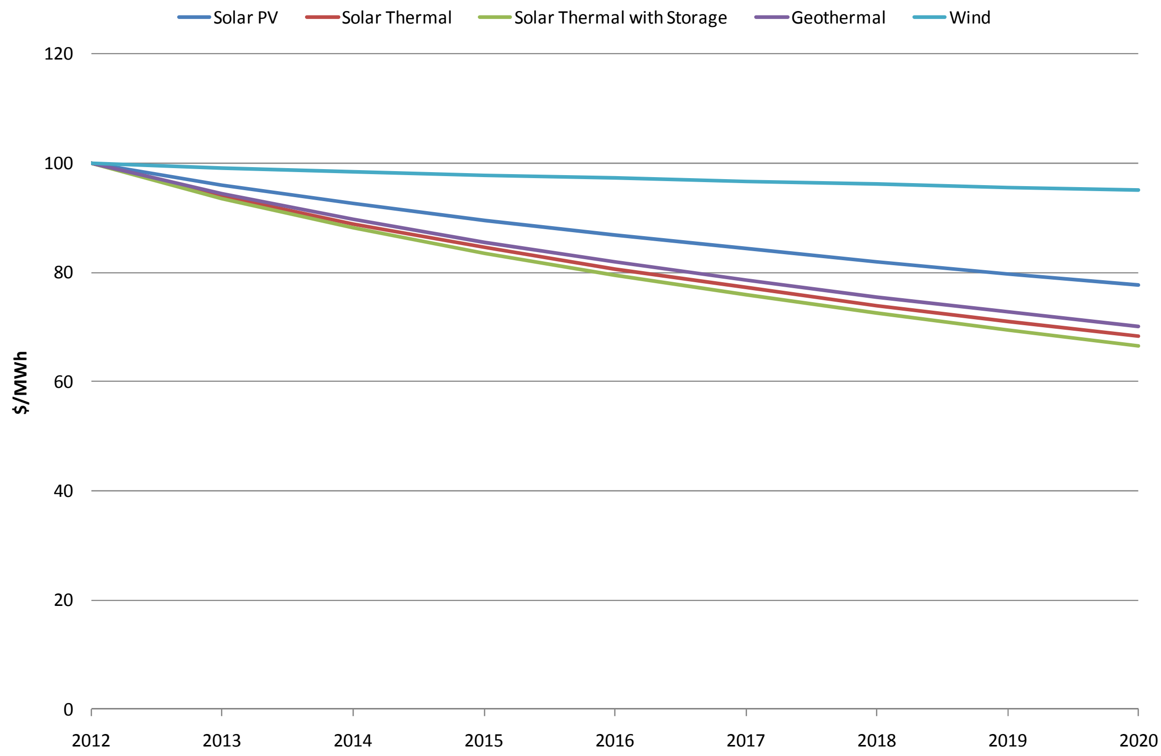
Power factors for capital costs de-escalation for each technology and learning by doing rates are based on a review of published estimates of capital cost movements and projected capital cost declines. Mean rates of decline in capital costs are sourced from:

- 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.

[21] 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.

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.

- **Figure 41: Index of de-escalation of capital costs by technology**



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

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[22], with the mean projection from these sources assumed.

A.2.2 Transmission costs

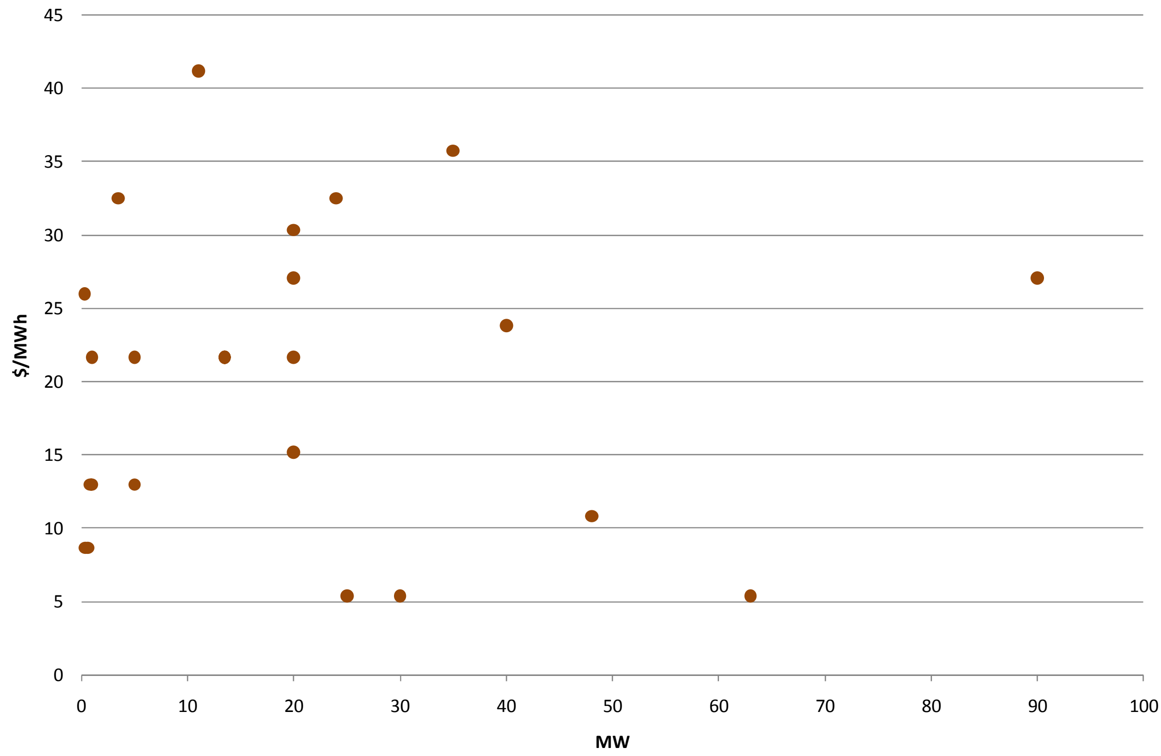
Transmission costs varied depending on the distance of the connection, the degree of any deep network upgrades and the voltage level required. Connection costs ranged from $110/kW to $500/kW.

A.2.3 Fuel costs

Biomass projects incurred a fuel cost. Estimates of fuel cost ranged from $5/MWh to around $40/MWh (see Figure 42). 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).

[22] Sources include ABARE, BREE, World Bank

▪ **Figure 42: Fuel cost assumptions, biomass**



A.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 for modest penetration of wind turbines in each State and were ramped up to $30/kW 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.3 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).

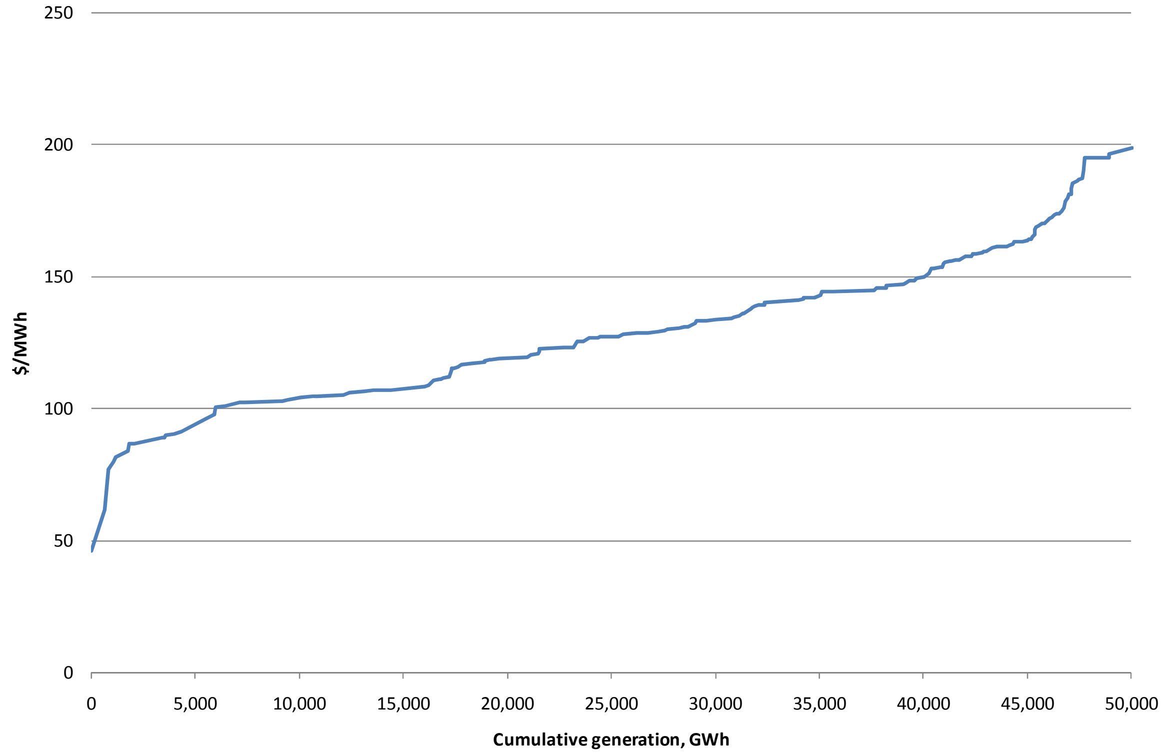
Assumptions on the cost of renewable generation are shown in Table 12. The long run marginal cost curves for available renewable energy in Australia are shown in Figure 43. The long run marginal cost in 2012 ranges from around $50/MWh (typically for upgrades that expands output) to around $280/MWh. Most 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 12: 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 43: 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.

Appendix B 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 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.

B.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[23].

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

B.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). This model is based on the Strategist probabilistic market modelling software, licensed from 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 four 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.

[23] AEMO (2012), *National Electricity Forecasting Report for the National Electricity Market*, June, Melbourne

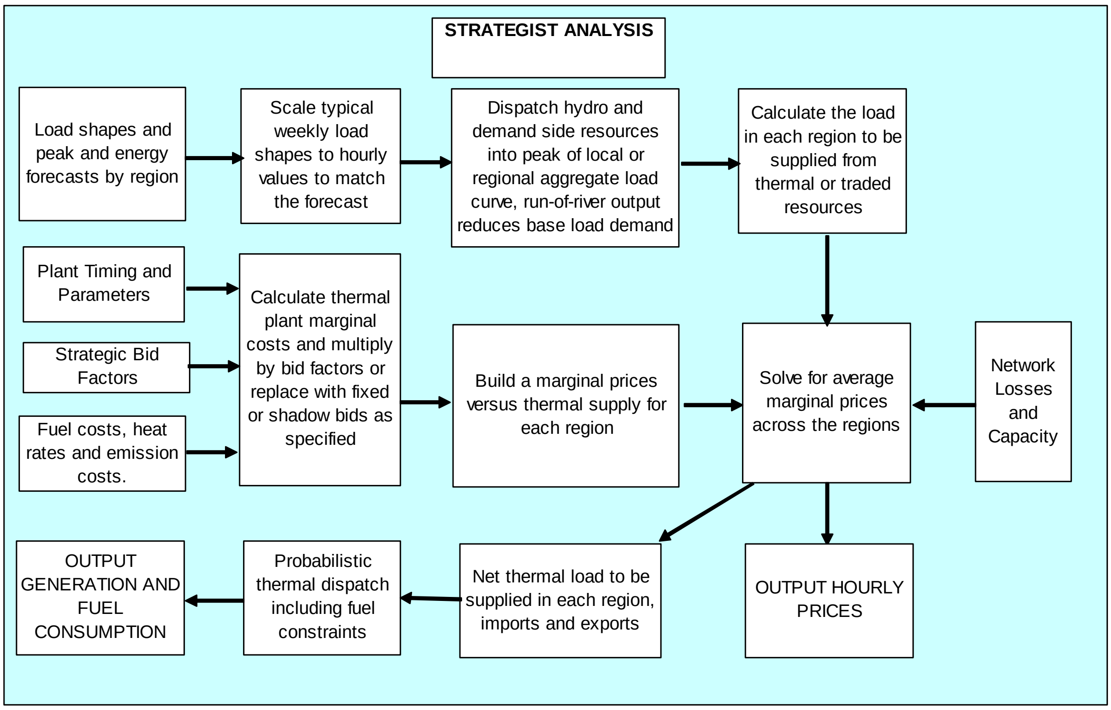
- Extreme peak demands and the associated gaming opportunities are not fully weighted. These uncertainties are highly skewed and provide the potential for very high price outcomes with quite low probability under unusual demand and network conditions.
- Marginal prices between regions are averaged for 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 TRUenergy 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. Specific supply/demand scenarios can be provided to quantify unusual market conditions.

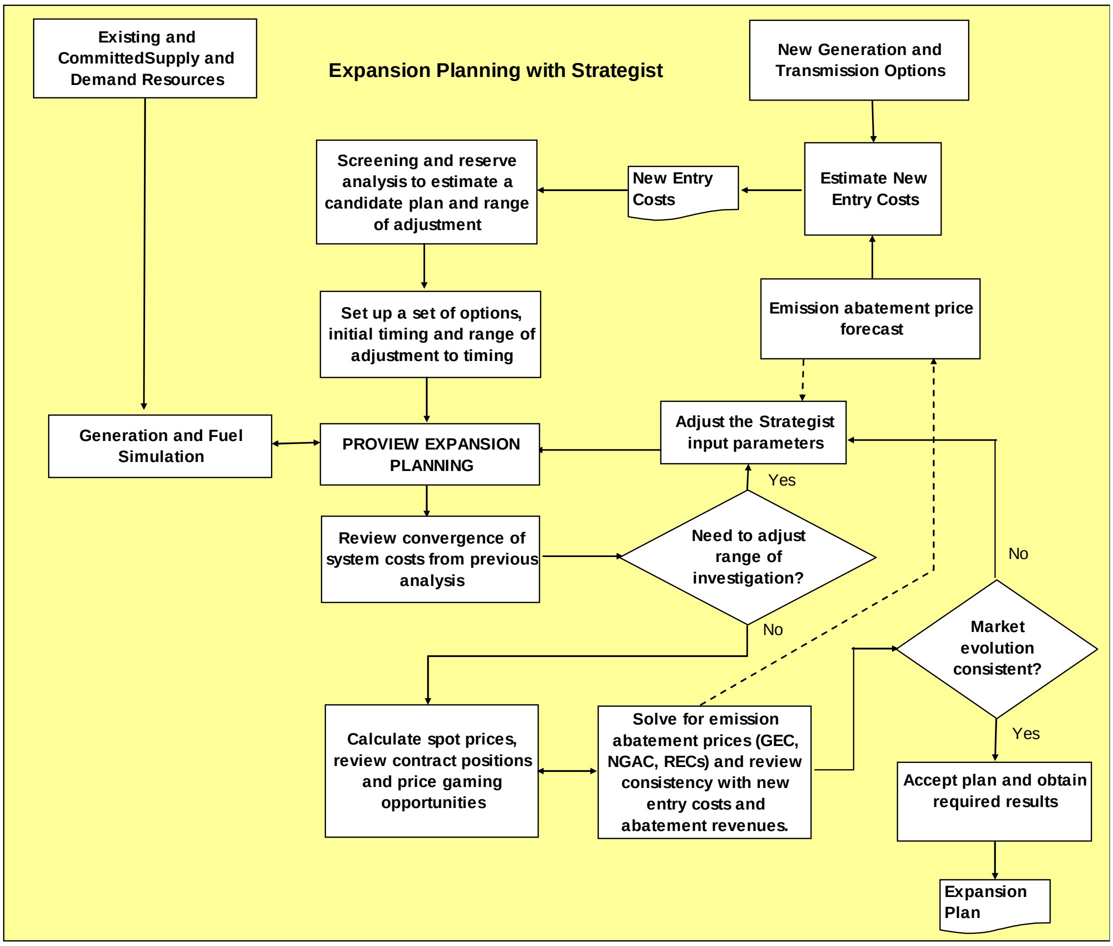
B.3 Strategist Methodology

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 44 and the MMA modelling procedures for determining the timing of new generation and transmission resources, and bid gaming factors are presented in Figure 45.

Figure 44 Strategist Analysis Flowchart



■ **Figure 45 MMA Strategist Modelling Procedures**



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).
- A review of the contract positions and the opportunity for gaming the spot market prices.

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.

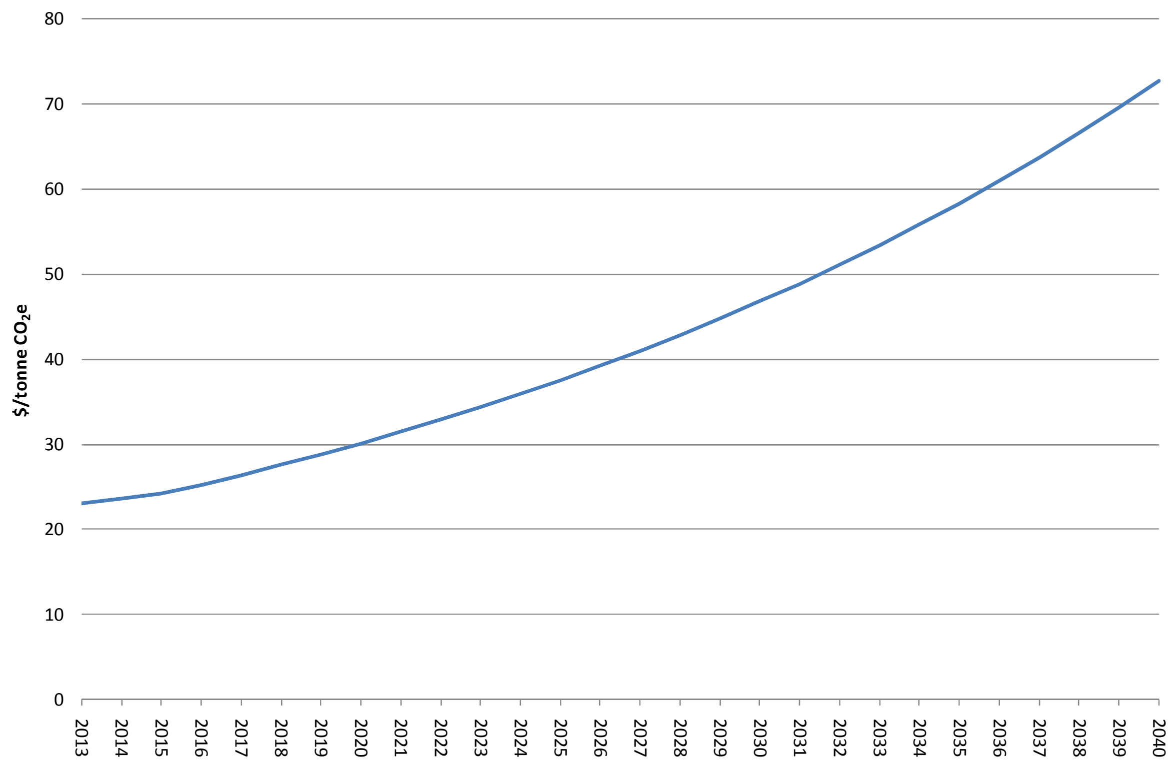
B.4 Assumptions

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.

The carbon price is taken from the Treasury modelling for the Government policy with the carbon price in the first three years equal to the fixed price regime at \$23/t CO_2e, inflated at 2.55 per annum in real terms. The price in the flexible price period starts at \$26/t CO_2e, escalating at 4.5% per annum in real terms. The carbon price path is shown in Figure 46.

- **Figure 46 Carbon price path**



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.
- The expanded RET scheme incorporated MRET and the previous VRET. The target as adjusted is for 41,000 GWh of large-scale renewable generation by 2020. The SRES is modelled as an uncapped take-up assuming a fixed price of $40/certificate in 2011, decreasing at 2.5% per annum in real terms.
- 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, we will not be considering it 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.

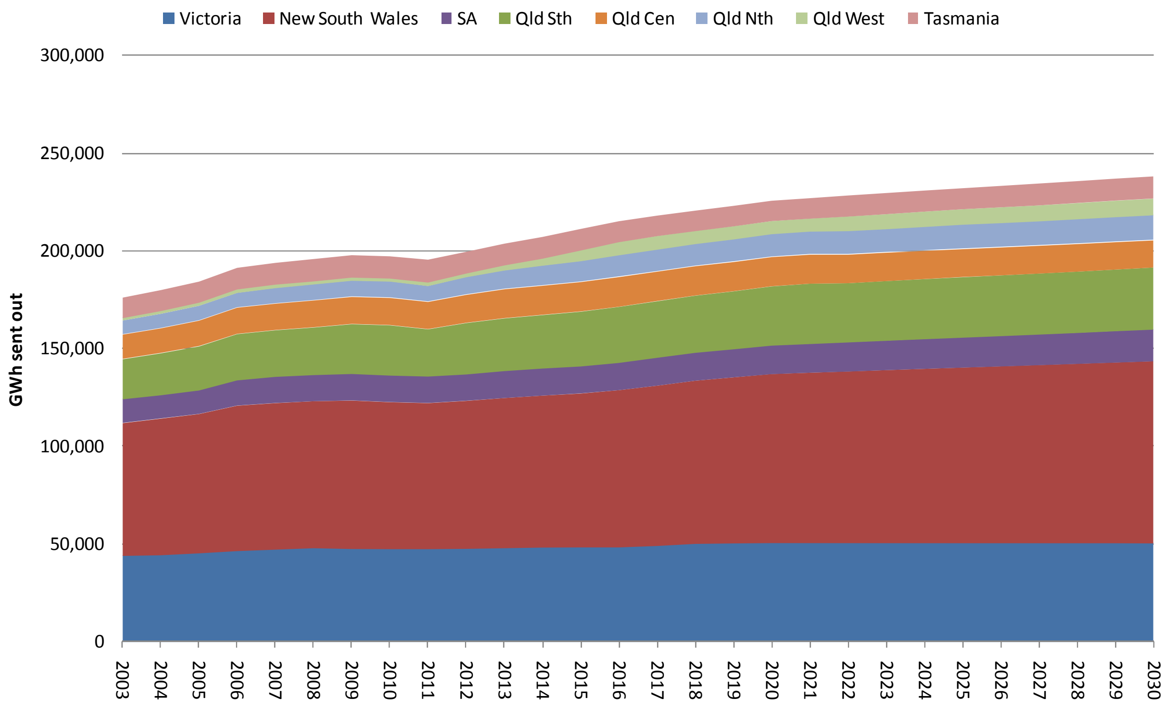
- The early retirement of Snuggery unit 3 is no longer expected. We have closed the three gas turbines by June 2020.
- Playford is retired in June 2012. It is possible for Playford to run longer as it has a high emission rate and may be required to be available to receive free permits. However, it is not considered critical to supply reliability except in extreme hot summer conditions.

B.5 Demand forecast and embedded generation

The demand forecast adopted by SKM MMA on AEMO's latest median forecast of electricity demand[24]. The forecast was applied to the 2011/12 actual half-hourly demand profiles and is shown in Figure 47 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. Over the long term, the average growth rate is 1.0% per annum compared with an average historical growth rate of 2.0% per annum. The lower growth rate reflect the impact of consumers' reaction to higher retail electricity prices, slower world economic growth rates and the impact of restructuring of the manufacturing sector.

The load supplied by embedded generation (e.g. roof-top solar PV systems) is included in the forecasts presented in Figure 47.

- **Figure 47 Medium demand growth forecast sent out**



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 the renewable energy.

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[24] AEMO (2012), National Electricity Forecasting Report for the National Electricity Market, June, Melbourne

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.

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 13). 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.

- **Table 13 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).

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.

B.6 Supply

B.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 14. 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 14 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

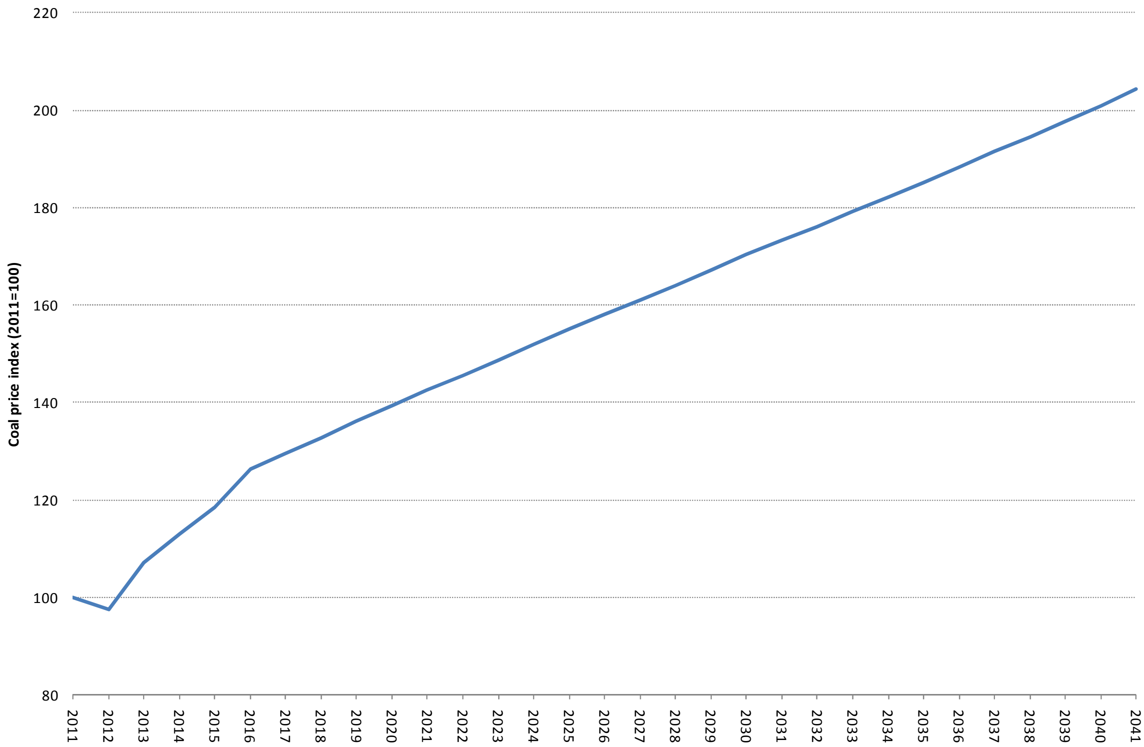
B.6.2 Fuel costs

Gas price projections for incumbent and new entrant plant are detailed in Appendix C.

World coal price projections under a medium price scenario have been derived from a number of credible forecasters, including those of BREE[25] (formerly part of ABARE), the IEA[26] and Standard Chartered Bank[27]. The medium price scenario was chosen as the median price of all relevant scenarios presented in the above sources. This price path is treated as an index which will be applied to all coal-fired power stations in the NEM, except those located at the mine mouth. The exceptions to this were the Victorian brown coal fired power stations, and the mine mouth black coal power stations including Millmerran, Tarong, Tarong North and Kogan Creek. It has also been assumed that by 2020 the mine mouth black coal power stations would also begin tracking the world coal price.

[25] Bureau of Resources and Energy Economics, *Australian energy projections to 2034-35*, Dec. 2011
[26] International Energy Agency, *World energy outlook 2011*, 2011
[27] Standard Chartered, *Super Cycle: A resource challenge*, Jan 2011

▪ **Figure 48 Coal price index for medium coal price scenario**



B.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%.

B.6.4 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.

B.6.5 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[28] 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,

[28] "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.

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 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.

B.7 Future market developments

B.7.1 Committed and planned entry

The recently developing power projects and reserve plant are shown in more detail in Table 15. 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 2011 ESOO. It also shows other projects for which, according to the 2011 ESOO, planning is well advanced. Table 15 demonstrates that new entry is alive and strong in the NEM with plenty of new projects in the pipeline to meet projected demand. The table does not include renewable energy generation projects.

B.7.2 Interconnections

Assumptions on interconnect limits are shown in Table 16 and their current operating levels are illustrated in Figure 49. The export limit from South Australia to Victoria 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. 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[29] .

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

[29] 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.

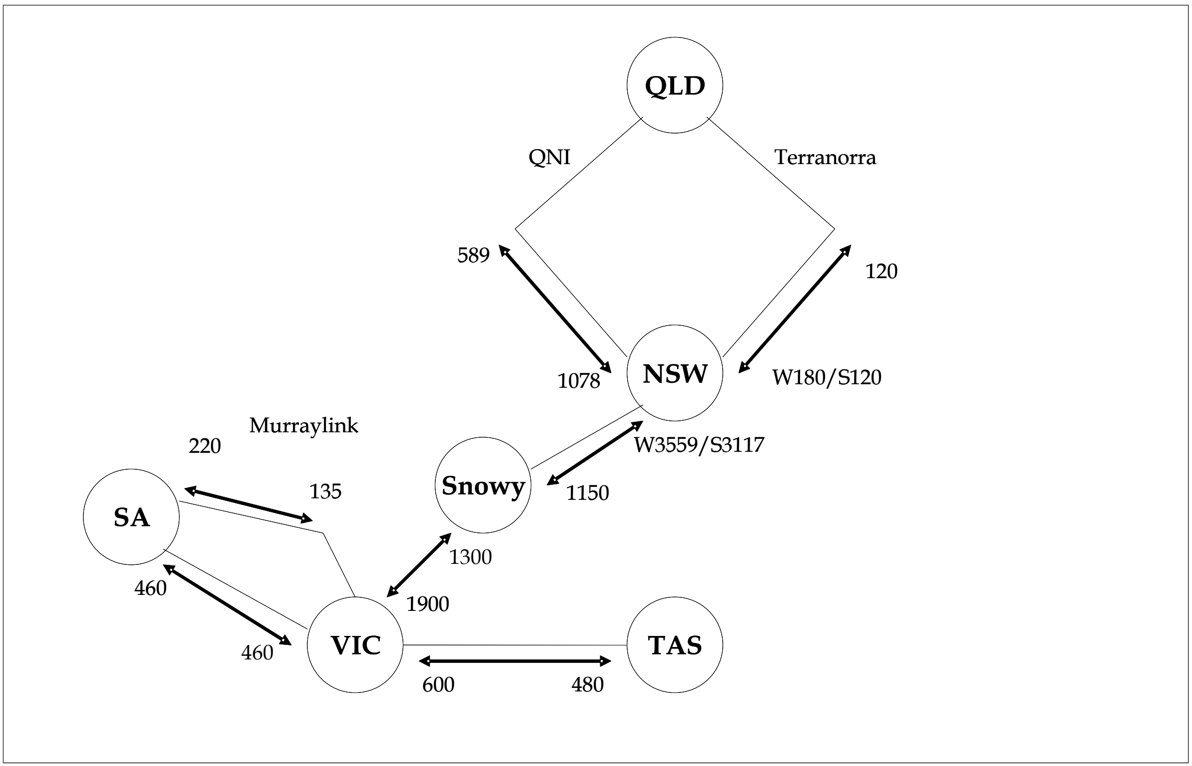
▪ **Table 15 Mothballed and reserve capacity and recently developed new plants in the NEM**

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
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

Table 16 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	

Figure 49 Representation of interconnectors and their limits



Basslink has a continuous capacity of 480 MW and a short-term rating up to 600 MW. Prior to 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.

B.7.3 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 17.

The minimum reserve level for VIC and SA combined is now 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 17 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:

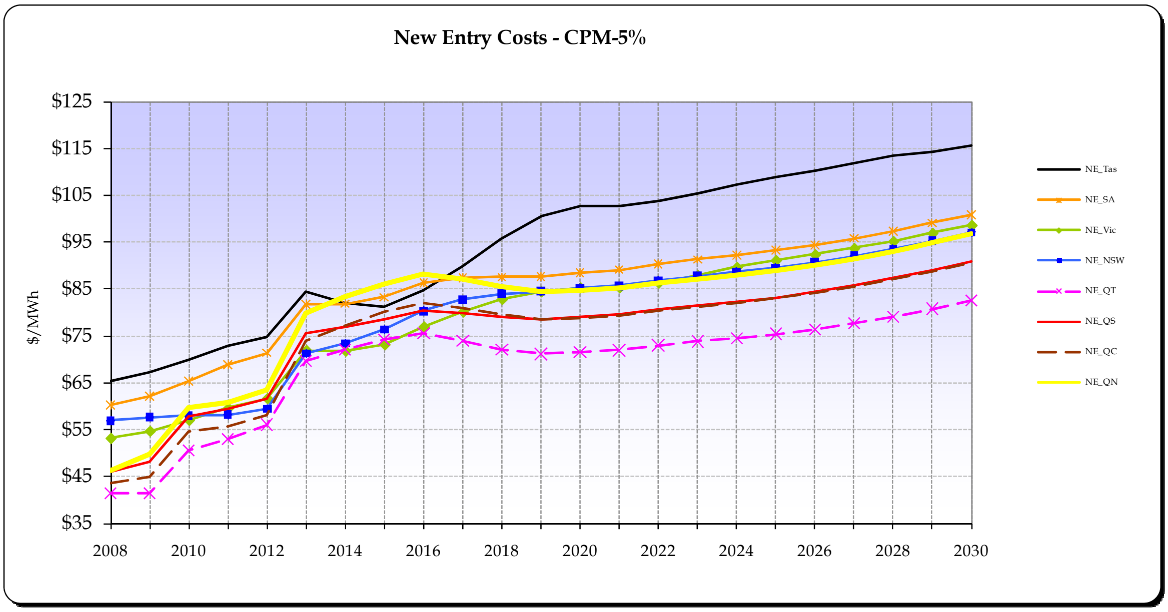
- Some 75% of base load plant capacity will be hedged in the market and bid at close to marginal cost to manage contract position.
- New entrants will require that their first year cash costs are met from the pool revenue before they will invest.
- The next new entrants in Victoria will be either peaking 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 50 in June 2012 dollars. 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.

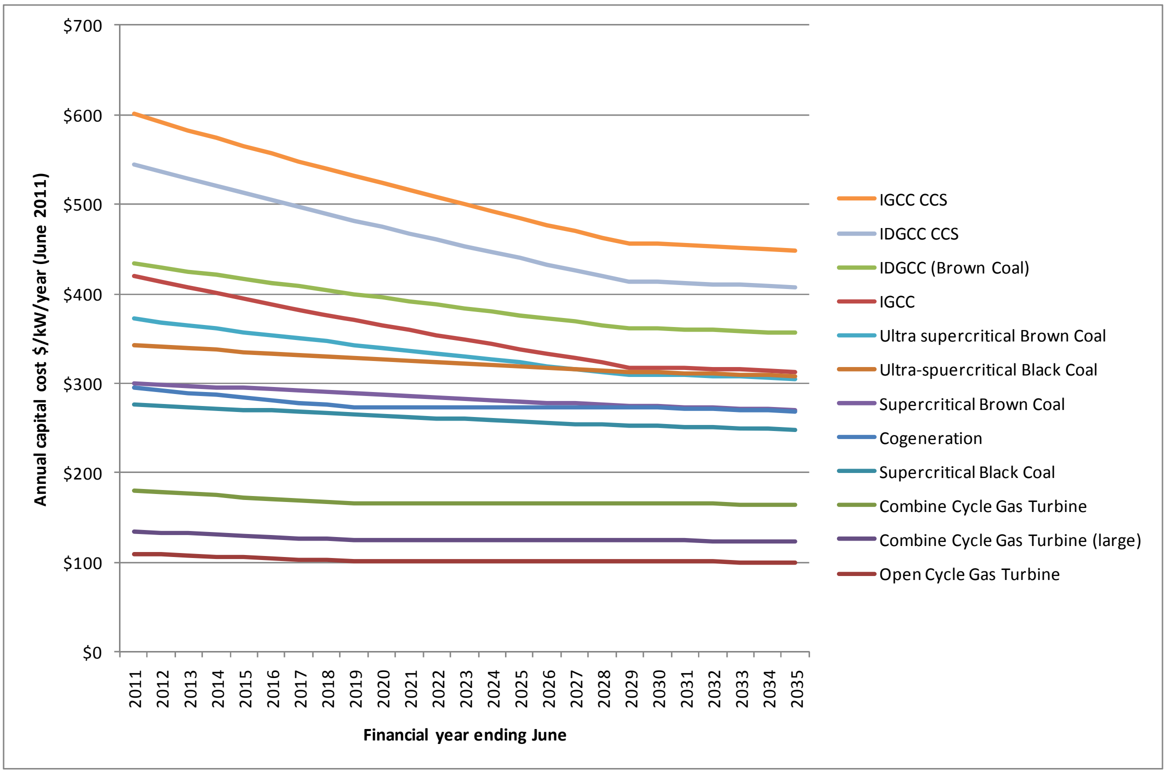
In general, the new entry prices increase as a result of:

- 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 50 New entry prices with carbon pricing from July 2012 (June 2012 $/MWh)**



- **Figure 51 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 18 applicable to the financial year 2014/15 in June 2012 dollars. The trend in annualised capital recovery costs is shown in Figure 51. 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 18 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 18 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. The unit's true LRMC measured in $/MWh is higher than this level. For example, we would be more likely to find a new CCGT operating in Victoria with a capacity factor of around 60% to 70% rather than the 92% as indicated in the table. Ideally, in determining the timing of new entry of such a plant we would compare the new entry cost of a CCGT operating at this level against the time-weighted prices forecast in the top 60% to 70% of hours. However this would require more detailed and timely analysis and in our experience does not yield 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 losses currently applied are those published in the AEMO 1 April 2010 Report "List of Regional Boundaries and Marginal Loss Factors for the 2010/11 Financial Year". We have not yet been able to process the later values published in 2011.

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.

B.8 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 19 and Table 20 show the monthly energy used in our model for the smaller hydro schemes.

Table 19 Monthly energy for small hydro generators modelled in Strategist, GWh

Month	Barron	Hume (Vic)	Kareeya
Jan	15.93	7.62	26.83
Feb	30.92	8.60	13.45
Mar	20.80	9.27	21.48
Apr	18.74	8.41	20.59
May	11.80	6.04	36.35
Jun	15.93	0.00	47.36
Jul	11.80	0.00	26.24
Aug	17.05	0.00	32.78
Sep	13.49	6.04	28.91
Oct	19.11	10.84	28.62
Nov	4.87	9.91	28.32
Dec	6.93	8.54	26.54
Total	187.38	75.26	337.46

Table 20 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

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.

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 201 the Murray annual energy has been reduced to 1,795 GWh per annum. Table 21 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 21 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

Appendix C 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.

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

All market participants pay for the ancillary services. In 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.

C.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.

C.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%.

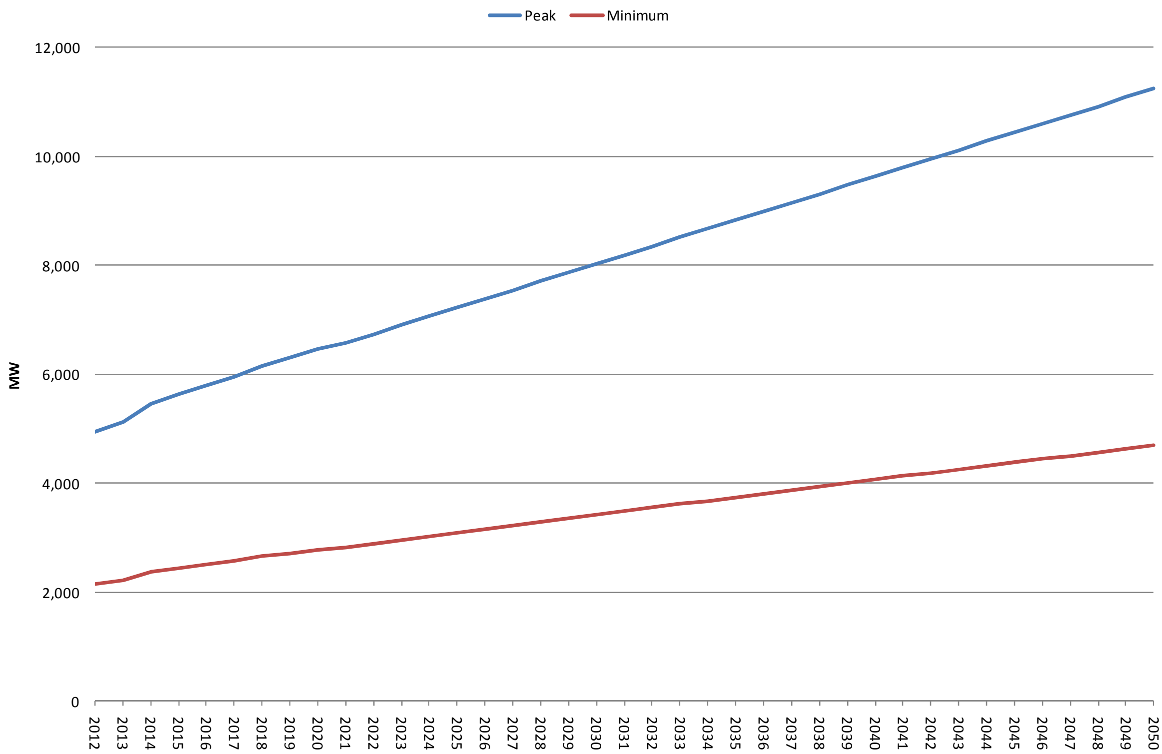
Projections of the summer and winter peak demand at generator bus bar are derived from forecasts of sent out peak demand provided by the IMO.

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 52. 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 52: Peak and minimum (base load) demand forecasts – median scenario**



C.4 Generation assumptions – existing units

Verve Energy

Verve Energy has 11 power stations operating in the SWIS, as shown in Table 22. 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 10% to 20% capacity factor. Cogeneration plants are assumed to operate as must-run plants due to steam off-take requirements.

The South West Cogeneration Joint Venture is comprised of 50% Origin Energy and 50% Verve Energy. Approximately 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 2013.

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

Table 22: 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 23: 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.

Other generators

Private generating capacity, including major cogeneration, is detailed in Table 24. 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 24: 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.

C.5 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 25: 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.

C.6 Fuel assumptions

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

Coal Prices

In the SKM MMA model, coal prices after 2010 are assumed to be $55/t on a delivered basis with an energy content of 19.3 GJ/t. This coal price is SKM MMA data based on market knowledge.

Coal prices are assumed to increase by 1% per annum in real terms in the median scenario and 2% per annum in real terms for the high scenario. They remain at $55/t for the low scenario.

Gas prices

SKM MMA assumes that gas supply will be priced at $7.50/GJ (well-head) for base load supply in 2011 with price escalating at 2% per annum in real terms in the median scenario. These assumptions are based on market data with the gas price escalations based on IEA projections of real world gas prices.

The transport charge is $1.50/GJ escalating at CPI.

All stations owned by Goldfields Power and Southern Cross Power are modelled to use gas with a well head price $7.00/GJ in 2009, escalating at 1% per annum in real terms in the median scenario. The gas transmission charge is assumed to be $3/GJ for gas supplied to the Goldfields region, reflecting the distances gas needs to be transmitted in this region, increasing at CPI.

Appendix D Gas Market Model

The supply of gas for electricity generation is often contracted with a take-or-pay type of arrangement where a gas customer (e.g. power station) pays for a volume of gas whether or not the customer consumes it. That is it becomes a sunk cost and when a generator is faced with an oversupply, it will choose to generate electricity in order to recover costs by selling it to pool market. If this were to happen during a low price period, it has the potential to further lower energy pool prices. More often, generators would reduce oversupply by scheduling extra generation during high price periods to obtain optimal benefit.

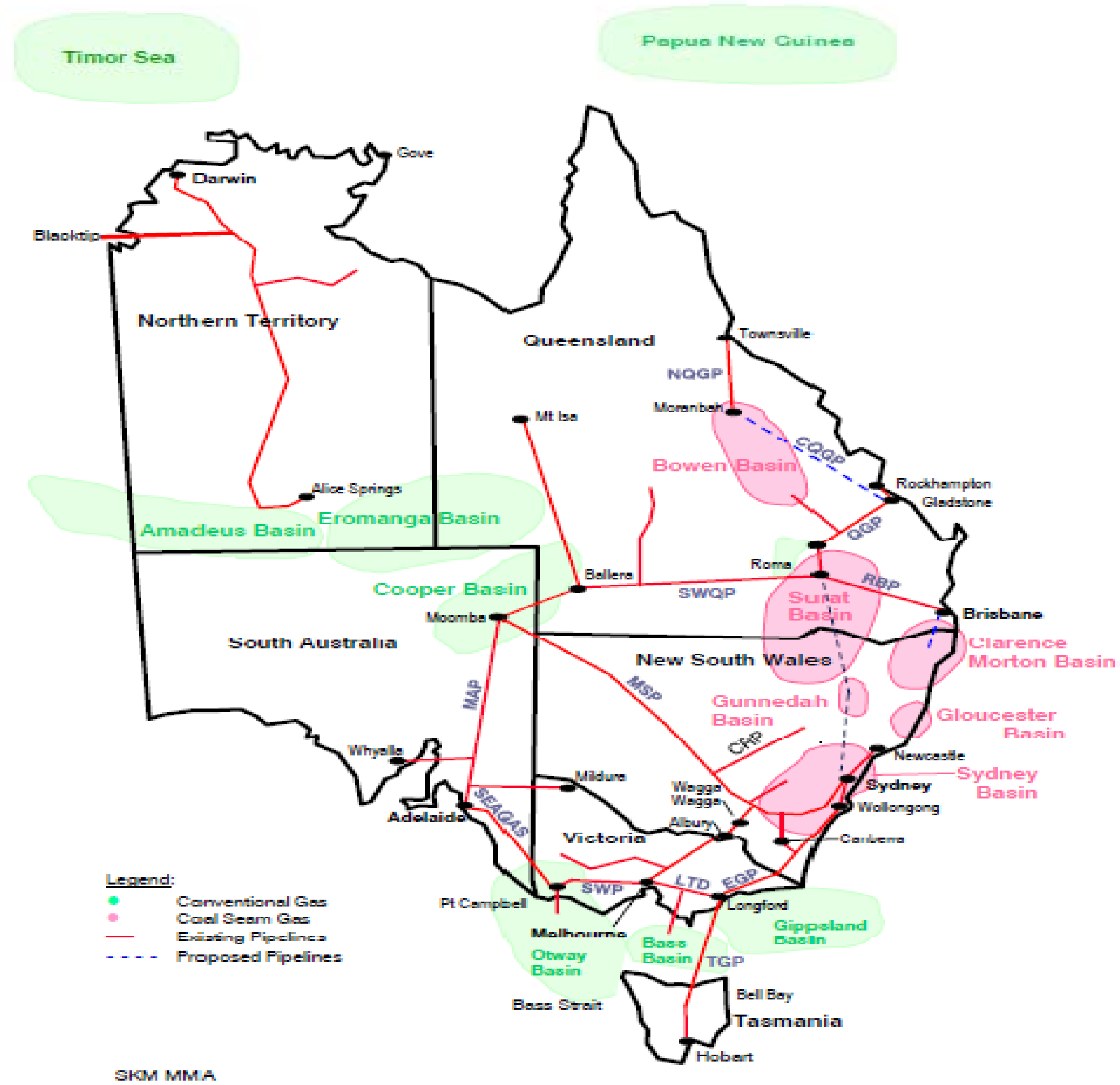
Two approaches are common for generating electricity from gas plants. Regardless of the source of the fuel, gas is used either as a peaking plant or in an immediate capacity. Due to its fast start capability gas fired generation can be called upon at short notice to meet periods of high demand or a sudden spike in demand. Open cycle gas turbine units are used for peaking capacity and run typically around 5% of time or less, each year. To recover their capital costs, these plant bid at very high prices. During high demand, one of the peaking units would become the marginal unit and therefore set the pool price. Since their bidding does not reflect their short-run marginal costs, increases in the cost of gas supply do not have a significant impact on electricity prices. Pool prices during these periods are already high.

In the intermediate mode, combined cycle gas turbines units supplement base load capacity based on their bidding strategy which, in part will reflect their short term costs such as fuel. Therefore, changes to the fuel costs will impact their bidding strategy and if they become the marginal plant, then the electricity prices would be directly impacted. Increasing gas prices has the potential to change the generation mix from existing power generators. Should the change be significant, it would change the merit order of plants and therefore impact on government policy options such as the carbon pricing mechanism. It is expected that under CPM, combined cycle plants would increasingly take the role of base load generation as coal options become expensive. High gas prices can prevent this merit order change, making the CPM policy ineffective.

In the long term, gas costs can also play role and determining the number and type of new entrants. Determining the composition of renewable, combined cycle gas turbine and open cycle gas turbine new entrants is a complex process and the final mix and timing of technology has direct impact on electricity prices.

SKM MMA prepares gas price forecasts based on projected demand-supply balance in Eastern Australia. The gas resources and delivery infrastructure in this region are illustrated in Figure 53. This chapter presents in detail SKM MMA's gas price forecasts, along with the assumptions underlying them.

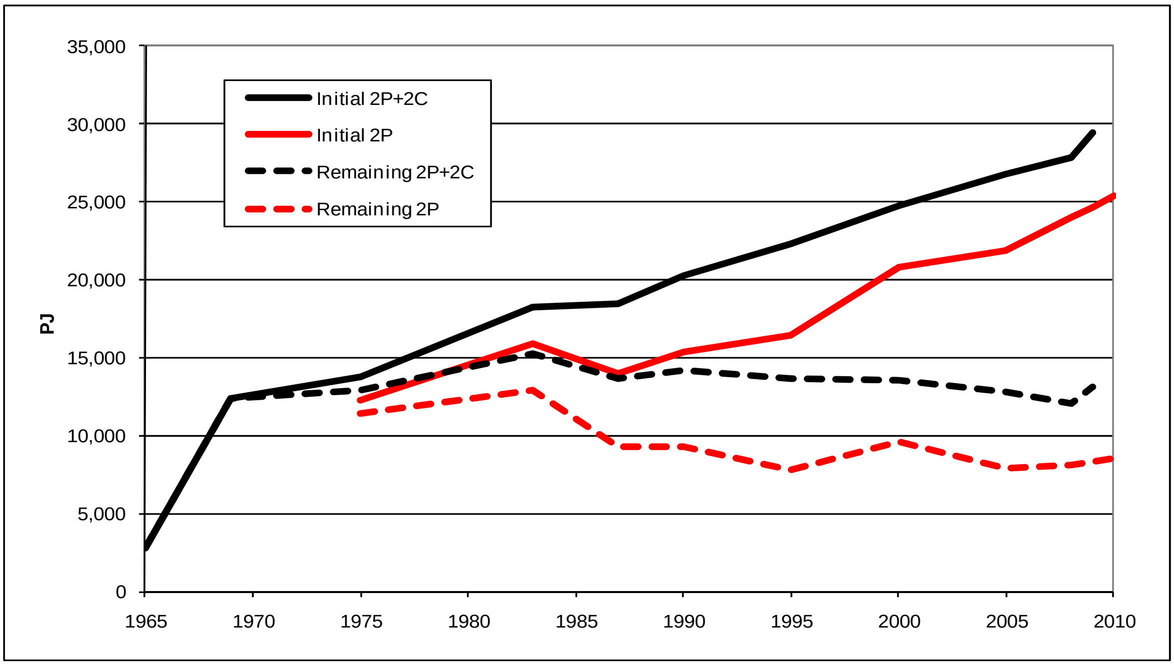
- **Figure 53 Gas basins and pipeline infrastructure, Eastern Australia**



D.1 Outlook for reserves and demand for gas

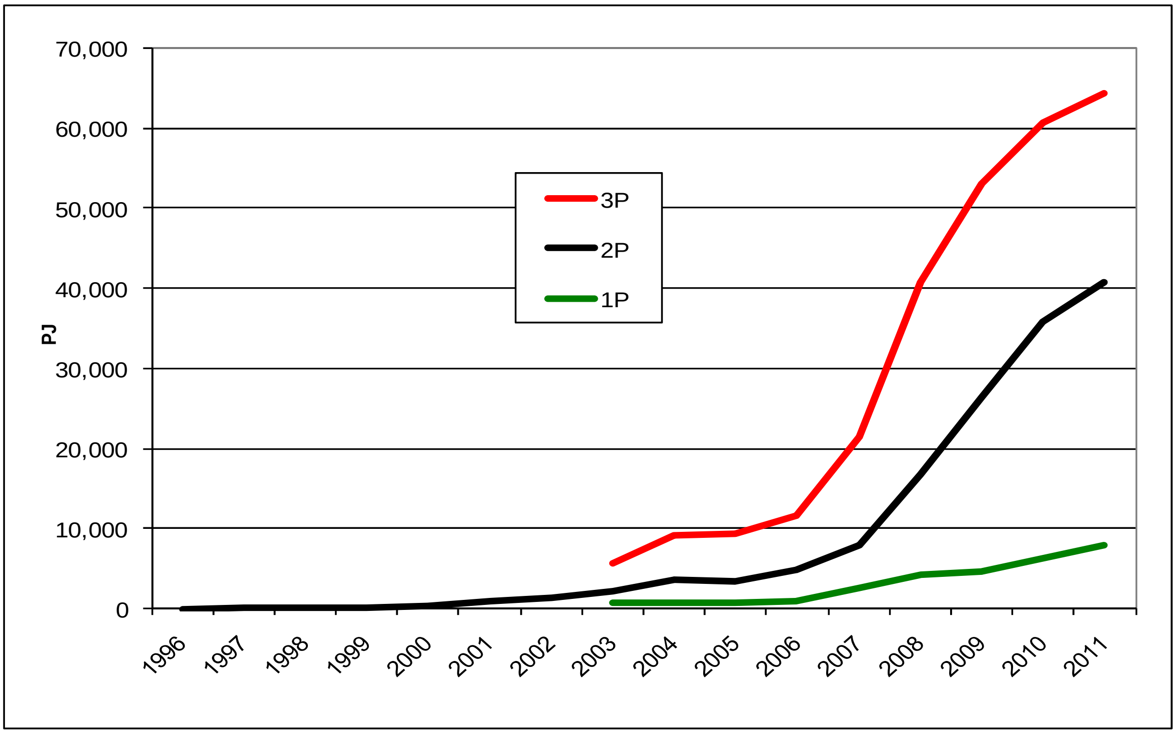
The Eastern Australian gas market has grown steadily since the late 1960s, supported by conventional gas reserves that have remained relatively static since approximately 1980 (refer to Figure 54). The past decade however has witnessed rapid growth of coal seam gas reserves (CSG), mainly in Queensland, to the extent that by 2008 it was clear that they could rapidly exceed domestic demand provided that a market could be found, otherwise the development may have stalled (Figure 55).

■ **Figure 54 Aggregate conventional gas resources and reserves, Eastern Australia (PJ)**



Note: 2P = proven and probable; 2C = proven and probable but contingent on price obtained.

■ **Figure 55 Aggregate CSG reserves, Eastern Australia (PJ)**



Notes: 1P = proven; 2P = proven and probable; 3P = proven, probable and possible.

Worldwide, the preferred technology to utilising excess[30] gas is LNG production. LNG is a global product that saw rapid growth and high prices during the oil price surge from 2003 to 2008. Since 2007 ten proposals have been put forward to export LNG from liquefaction plants with eight proposed for the Queensland coast (eight), and one each in New South Wales and South Australia. Three of the large projects at Curtis Island, near Gladstone, have now passed the final investment decision and their six LNG trains, each capable of delivering about 4 million tonnes of LNG per year, are under construction, with first deliveries scheduled in the period 2014 to 2016.

While there is every reason to believe that the CSG reserves to support some if not all of the LNG projects will eventually be proved up, none of the proponents currently has sufficient proved reserves for the likely duration of their project, for all the trains planned. A strong focus on building reserves for LNG projects has, in the short-term, led to a relative lack of reserves available to support new domestic gas contracts and domestic gas buyers have had difficulty securing such contracts.

D.2 Methodology

Australia's gas industry is undergoing a major structural change with the development of LNG facilities in central Queensland. With that development, eastern seaboard gas producers will have the opportunity to realise international benchmark prices for gas exported, rather than the low prices that have prevailed historically in the domestic market. However the LNG export market is unlike most other export markets in that the cost of liquefying the gas for export is approximately 50% of the cost and LNG plants are not built without the support of long-term purchase contracts. Consequently gas cannot readily be switched between domestic and export sales and long-term price disequilibria can prevail. In the medium term there is already a domestic shortage of gas because reserves and capacity have been over committed to export and it will take time for the shortfall to be redressed. In the longer term the equilibrium can easily be overshot because Australian LNG project cost overruns will drive the next projects to currently lower cost suppliers such as the US, Canada and East Africa. SKM's gas modelling captures the balance between these factors.

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To assess the future balance of gas demand and supply across Eastern Australia SKM MMA has:

1) Developed three energy-economic scenarios (low, medium, high), comparable to the scenarios used by AEMO in the 2011 GSOO, and for each scenario prepared:

    a) projections of future gas demand for the domestic sector, comprised of two sub-sectors:

        i) utility (residential and small medium business) and large industrial customers

        ii) gas for power generation including large cogeneration projects

    b) projections of the level of LNG exports from Eastern Australia, linked to global demand and supply conditions

    c) estimates of the timing of gas reserve commitments to long-term contracts to meet the above demand, taking into account existing reserves commitments to domestic contracts.

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[30] Gas that cannot reach a market by pipeline. LNG is preferred to conversion technologies such as Gas-To-Liquids

2) Reviewed gas reserves and determined potential reserves development profiles based on recent growth rates, currently known contingent and prospective resources and potential impediments to reserves appraisal such as recent flood events in Queensland.

3) Tested the ability of reserves growth to physically meet the timing requirements of new domestic and export contracts, taking into account the multi-train targets of LNG projects.

4) Reviewed other aspects of gas supply including likely future production and transmission costs

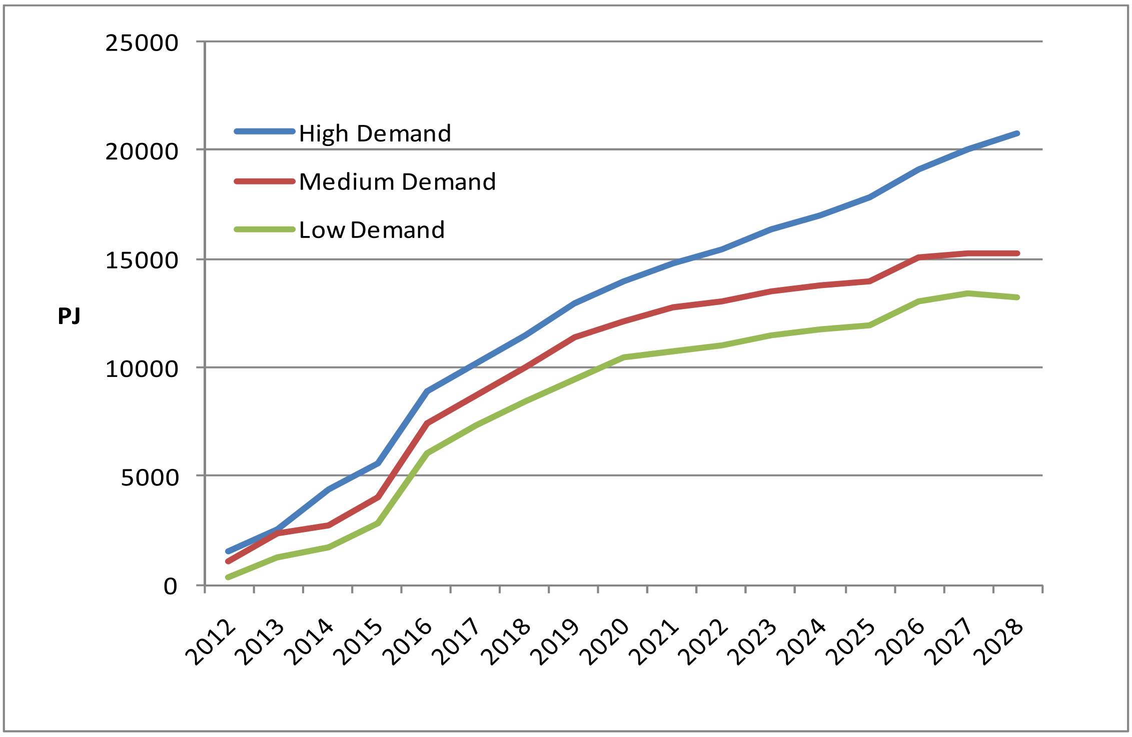
5) Modelled the economic balance of demand-supply and consequent price outcomes in the three scenarios

6) Examined the capacity expansion requirements for pipelines (in Queensland only)

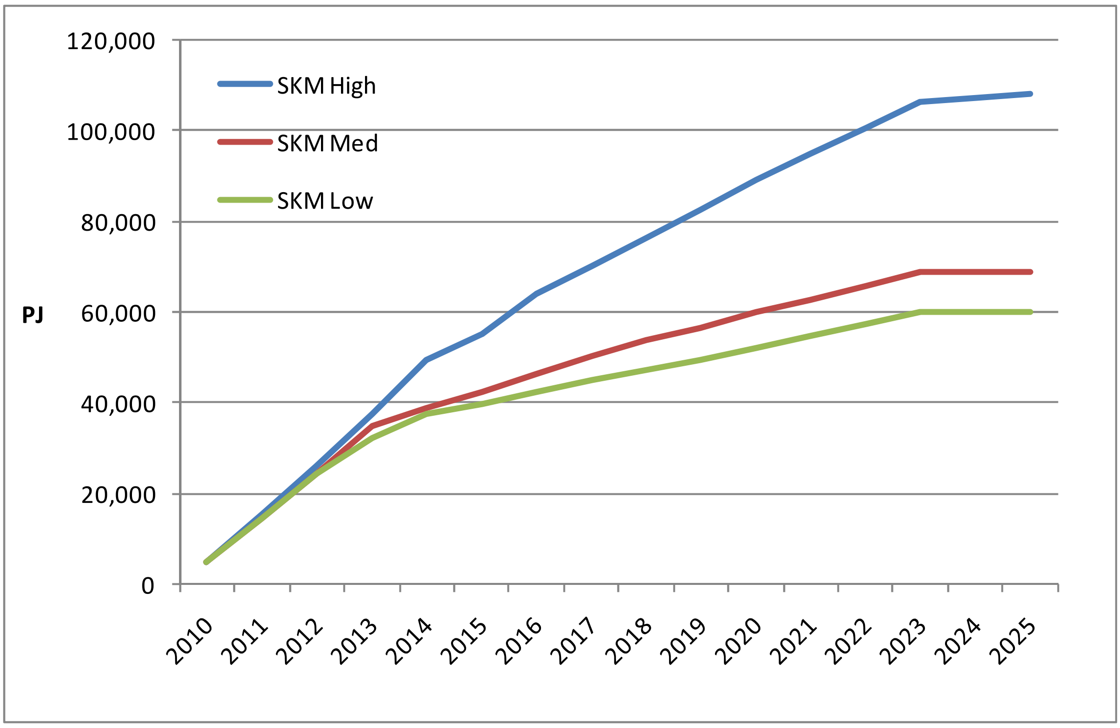
D.3 Physical demand-supply balance

Figure 56 and Figure 57 below illustrate the projected domestic and export reserves requirements respectively and demonstrate the potential for export requirements to considerably exceed those of the domestic market in the Medium and High scenarios. For both markets it is assumed that contracts are entered four years before first delivery, allowing for development of new production facilities and transmission capacity prior to first supply.

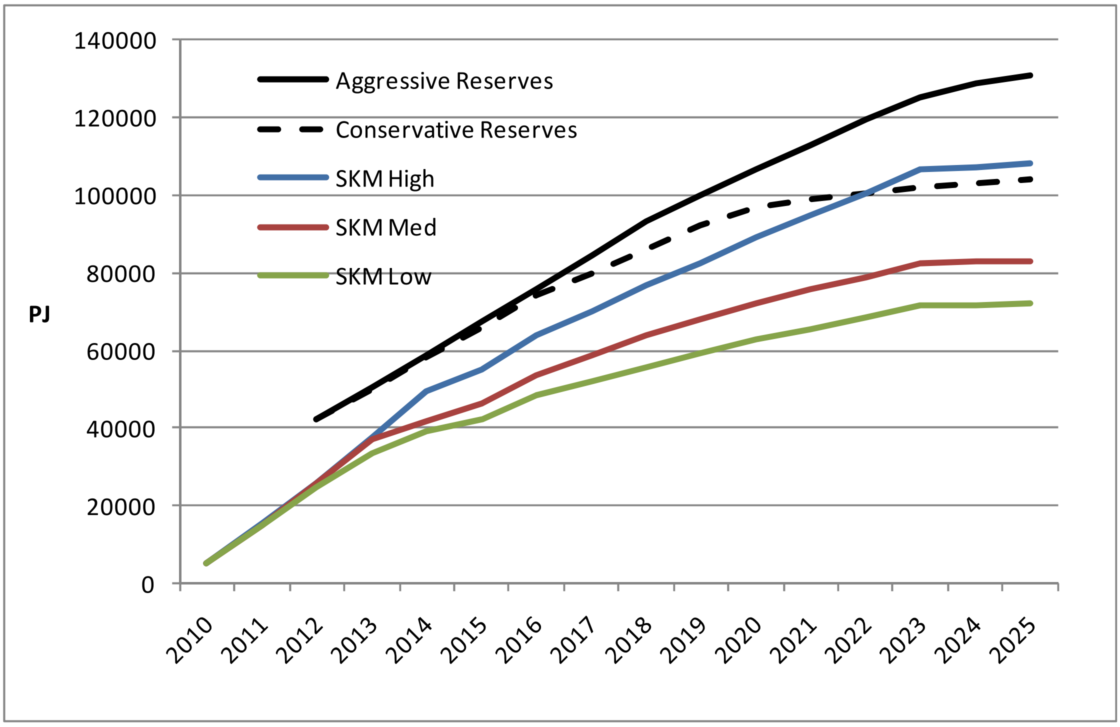
- **Figure 56 Cumulative domestic gas reserves requirements (PJ)**



▪ **Figure 57 Cumulative LNG export gas reserves requirements (PJ)**



▪ **Figure 58 Combined domestic and LNG reserve requirements versus 2P uncontracted gross reserve projections (PJ)**



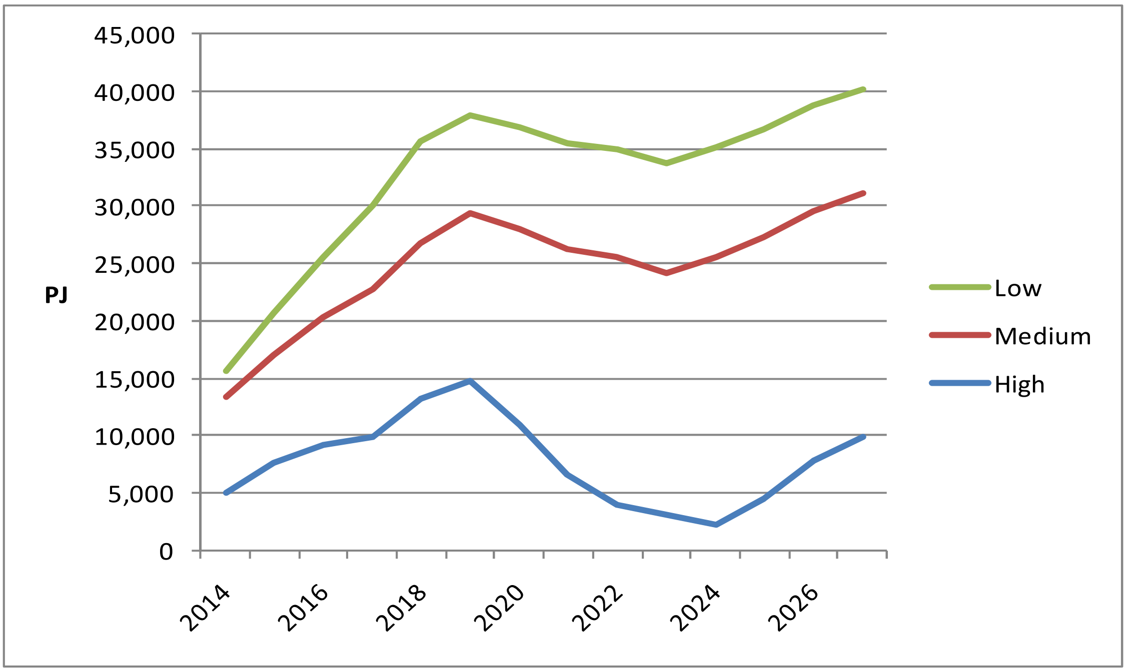
Aggregate domestic and LNG reserves requirements are compared with two reserves projections in Figure 58. The reserves projections represent growth at the maximum level that appears possible given current 3P and contingent resources (the Conservative case) and a case in which contingent

resources are assumed to be doubled by further exploration (the Aggressive case). The aggregate reserve requirements in the High Demand Scenario result in very limited 2P reserve margins being maintained until 2020. This margin will be maintained after 2020 only if there is continued growth of resources feeding into the more aggressive reserves projection. In reality the high domestic price will result in significant demand reductions that will also go some way to resolving the demand supply pressure. The aggregate reserve requirements in the Medium and Low Demand Scenarios can be met more readily, with larger margins extending into the long term, to the extent that reserve development at the maximum rate is unlikely to be required.

The adequacy of margins between 2P reserves and the demand for reserves to meet new contracts, even though it takes into account contracting four years ahead of first gas delivery, does not however imply that the amounts of reserves will be made available to the domestic market. Reserves likely to be made available to the domestic market are reduced by the LNG proponents need to build up reserves for multi-train projects and by uncertainties in the relationship between reserves and rates of gas production.

Gas reserves available for new domestic and third party LNG contracts (uncontracted and not pre-committed to future LNG) have been estimated taking these factors into account (Figure 59).

- **Figure 59 Gas reserves available for new domestic and third party LNG contracts, Eastern Australia (PJ)**



In the High Demand scenario the reserves available remain below 20,000PJ for most of the forecast period. Reserves available in the Medium and Low scenarios are considerably higher.

D.4 Economic demand-supply balance and price projections

The economic gas demand-supply balance has been determined in each scenario using SKM MMA's proprietary model, MMAGas, Market Model Australia – Gas, which replicates the essential features of Australian wholesale gas markets:

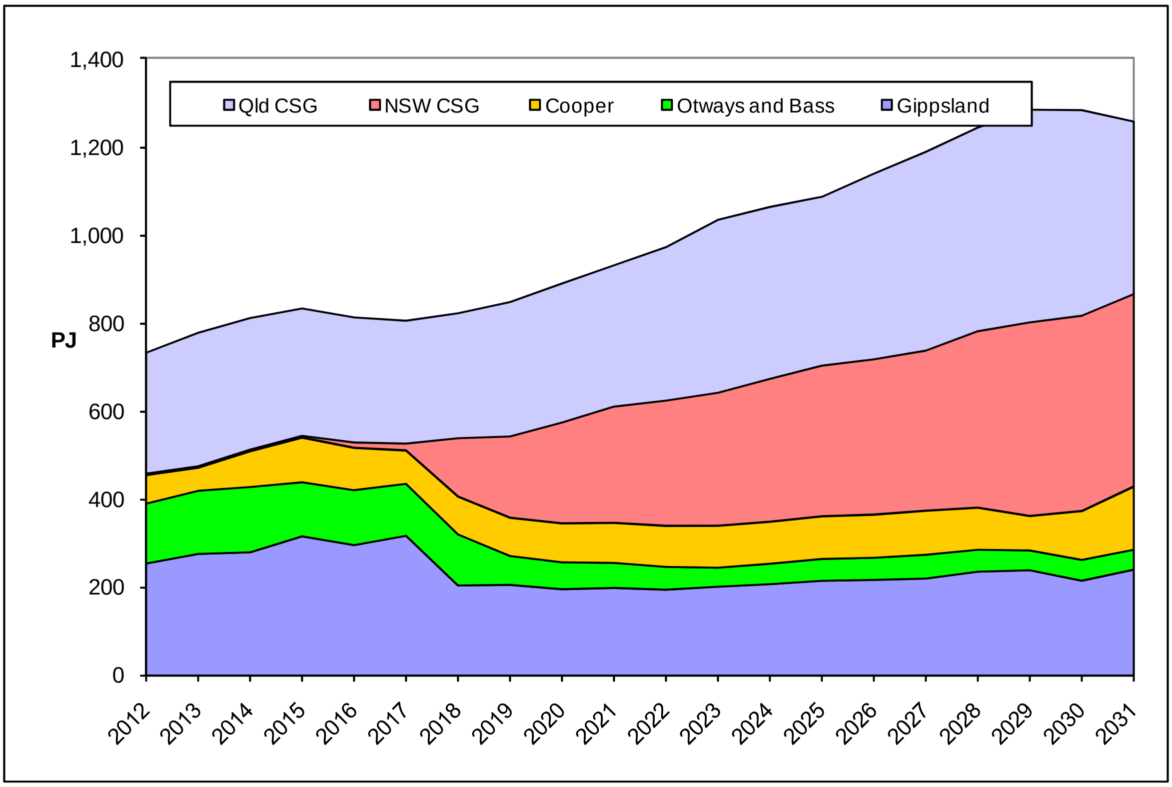
- A limited number of gas producers.
- Dominance of long term contracting and limited short term trading.
- A developing network of regulated and competitive transmission pipelines.
- Domestic market growth driven by gas-fired generation and large industrial projects.

Eastern Australian gas supply is projected to come increasingly from CSG, not only from Queensland but also New South Wales (Figure 60 and Figure 61).

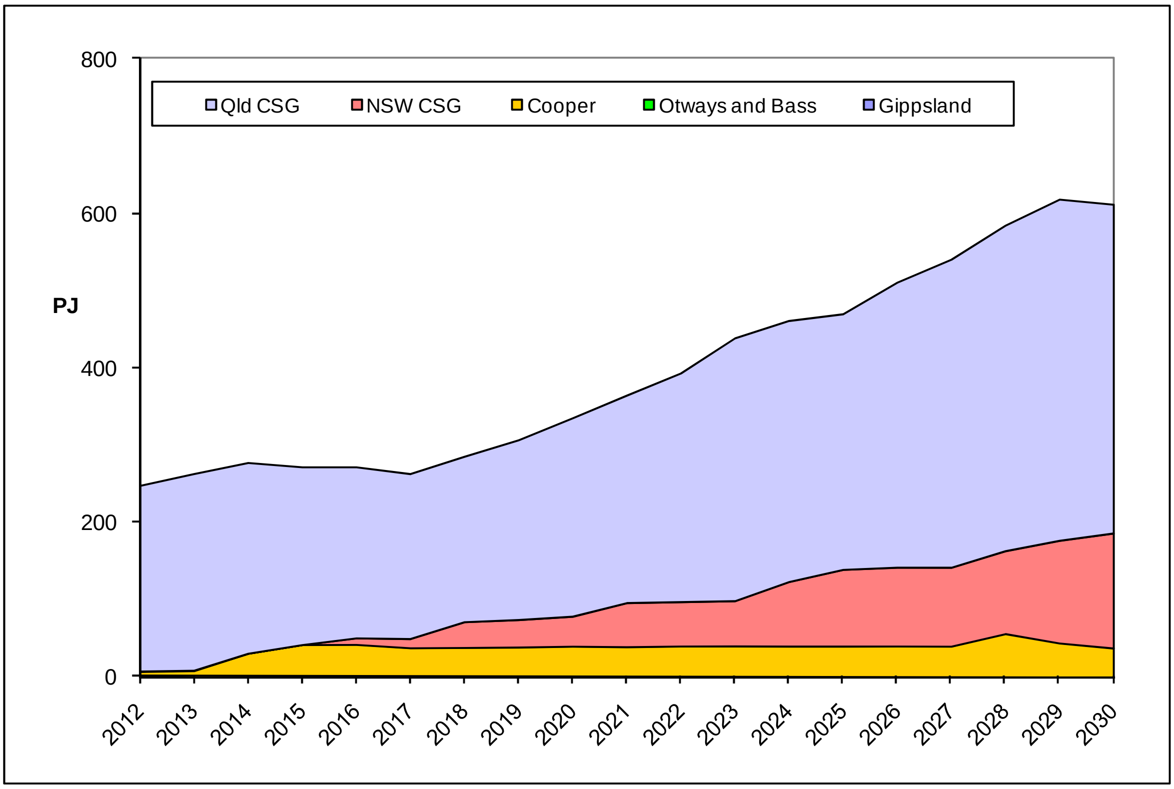
The domestic supply patterns vary considerably between scenarios, with less Queensland CSG in the High scenario, where it is more dedicated to export, and more NSW CSG and Cooper Basin gas.

Projected new contract delivered gas prices in Queensland also vary considerably between scenarios (Figure 63 to Figure 65). New contract prices are projected to rise by $3/GJ to $4/GJ initially in response to the lack of reserves created by the six initial LNG trains, in all scenarios. In the High scenario prices remain at this level because of continuing commitment to additional LNG capacity. However in the Base and Low scenarios additional LNG capacity commitment falls behind reserves growth and new contract prices fall. Similar patterns apply in all Queensland zones and average contract prices follow new contract prices with a considerable time-lag (Figure 64). Projected prices in the southern states (all regions except Queensland) also rise immediately but by a smaller margin of $1-2/GJ, reflecting the additional transmission cost discount on the LNG value (Figure 65 and Figure 66).

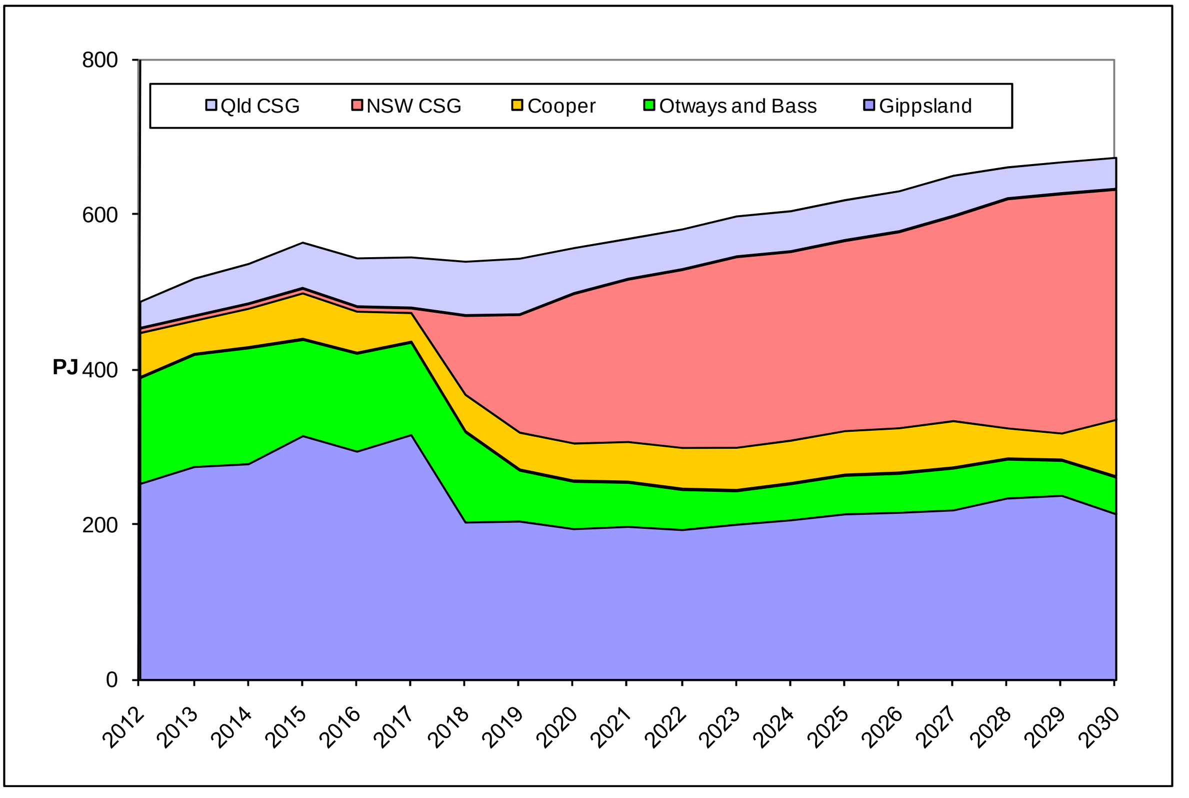
- **Figure 60 Projected gas supply, Eastern Australia domestic only, Medium Scenario**



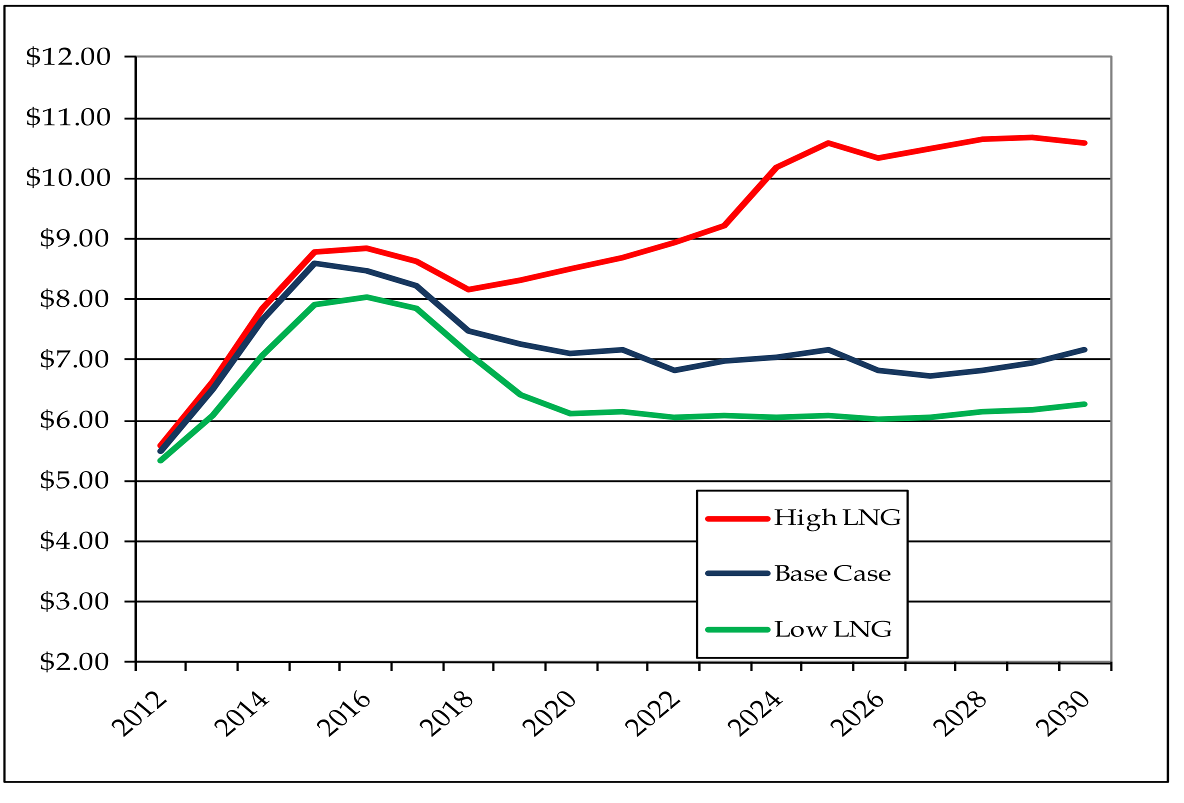
- **Figure 61 Projected gas supply, Queensland domestic only, Medium Scenario**



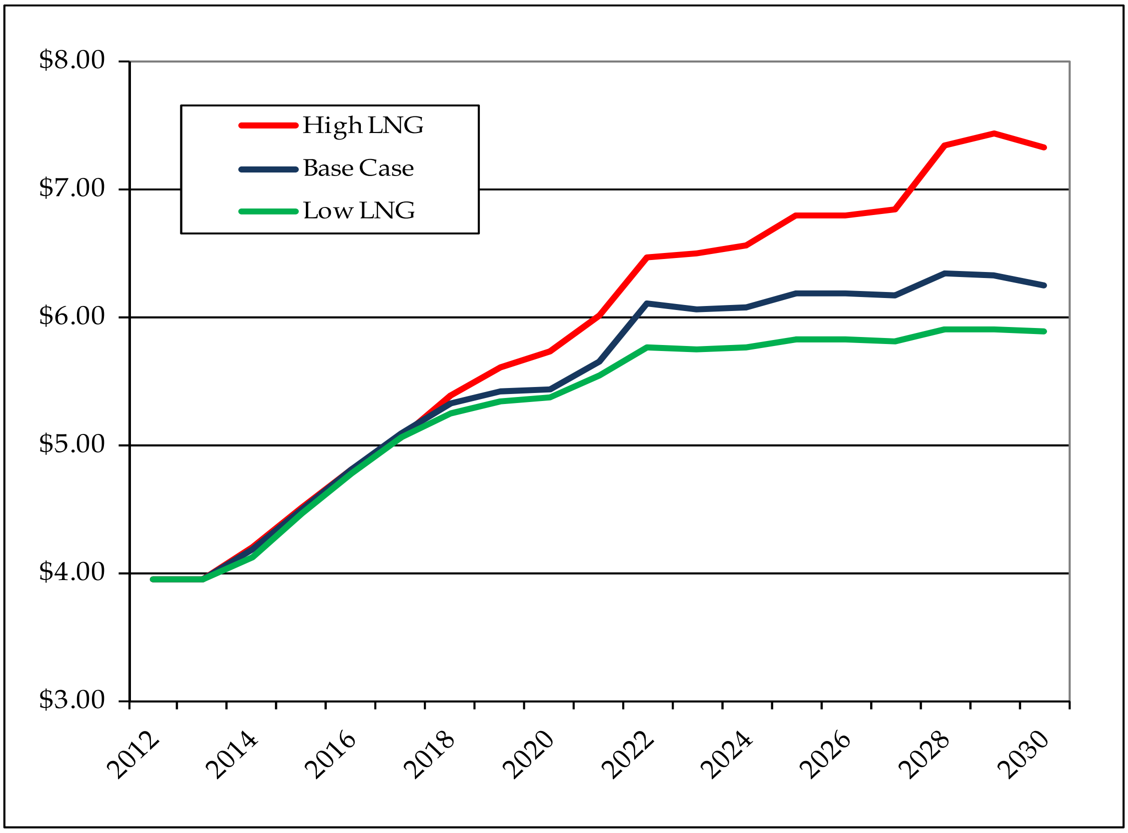
▪ **Figure 62 Projected gas supply, Southern States only, Medium Scenario**



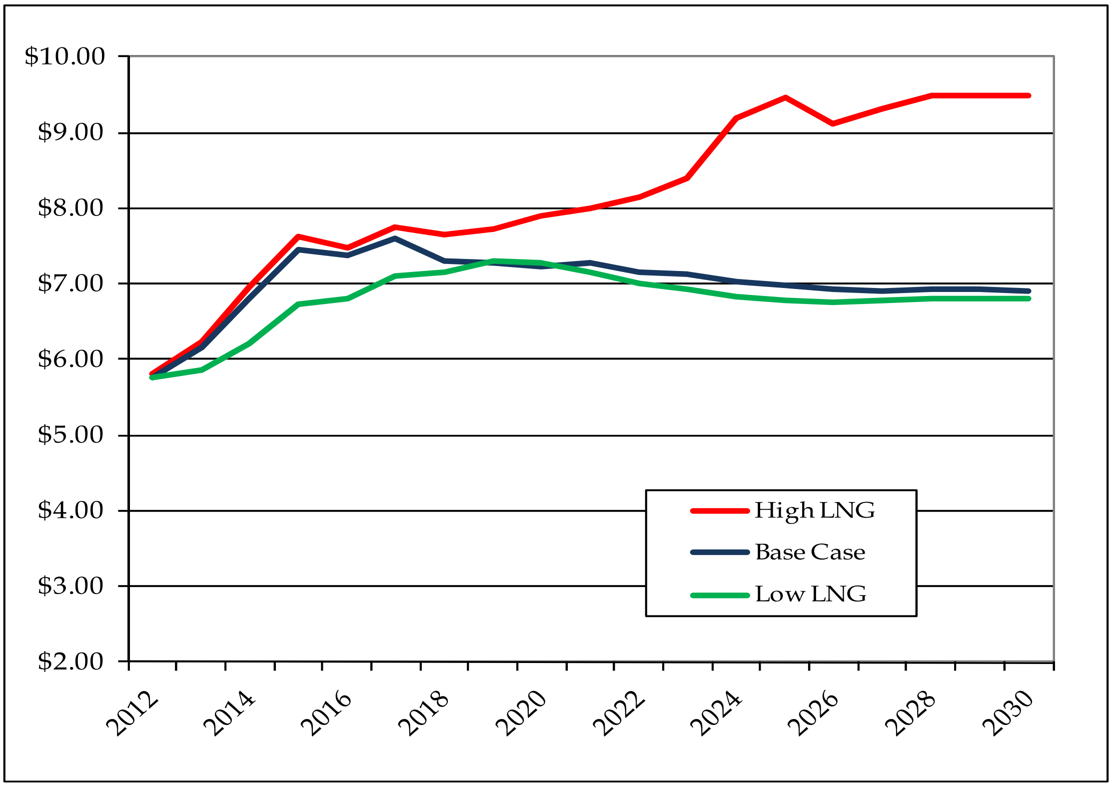
▪ **Figure 63 New contract delivered prices Queensland domestic aggregate, all scenarios ($/GJ, $2012 real)**



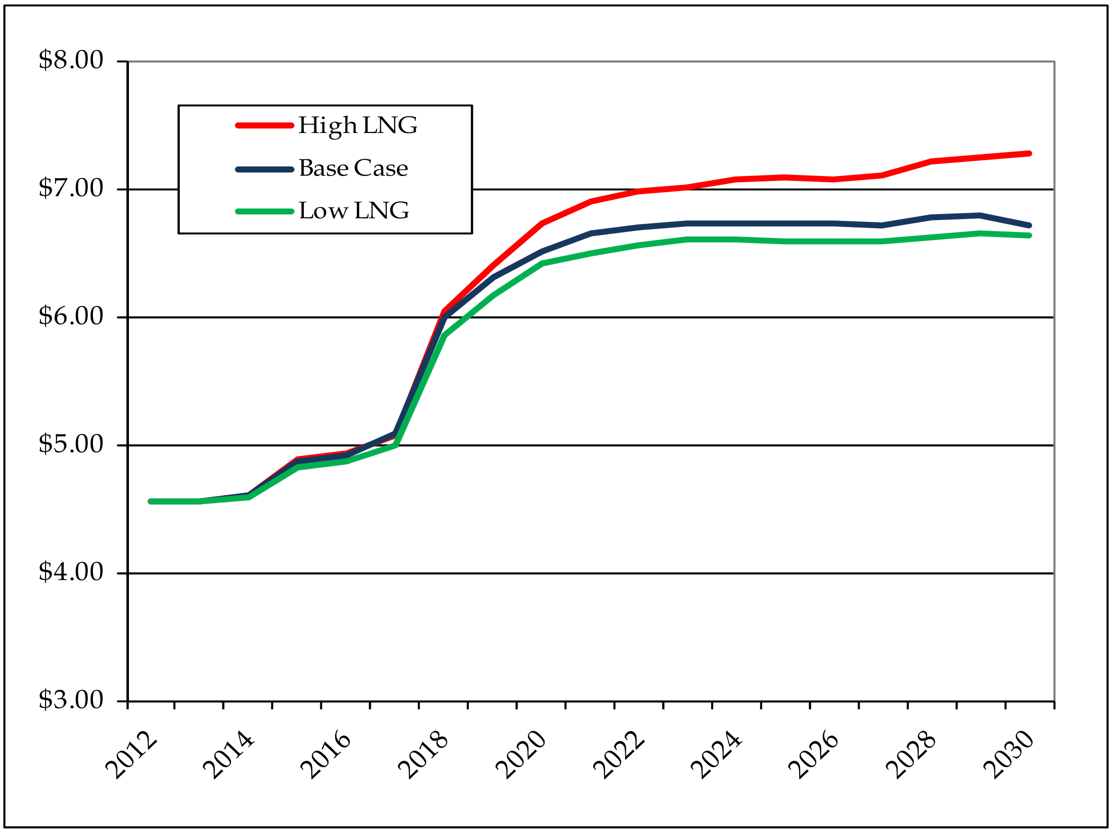
- **Figure 64 Average contract delivered prices Queensland aggregate, all scenarios ($/GJ, $2012 real)**



- **Figure 65 New contract delivered prices southern states aggregate, all scenarios ($/GJ, $2012 real)**



- **Figure 66 Average contract delivered prices Southern States aggregate, all scenarios ($/GJ, $2012 real)**

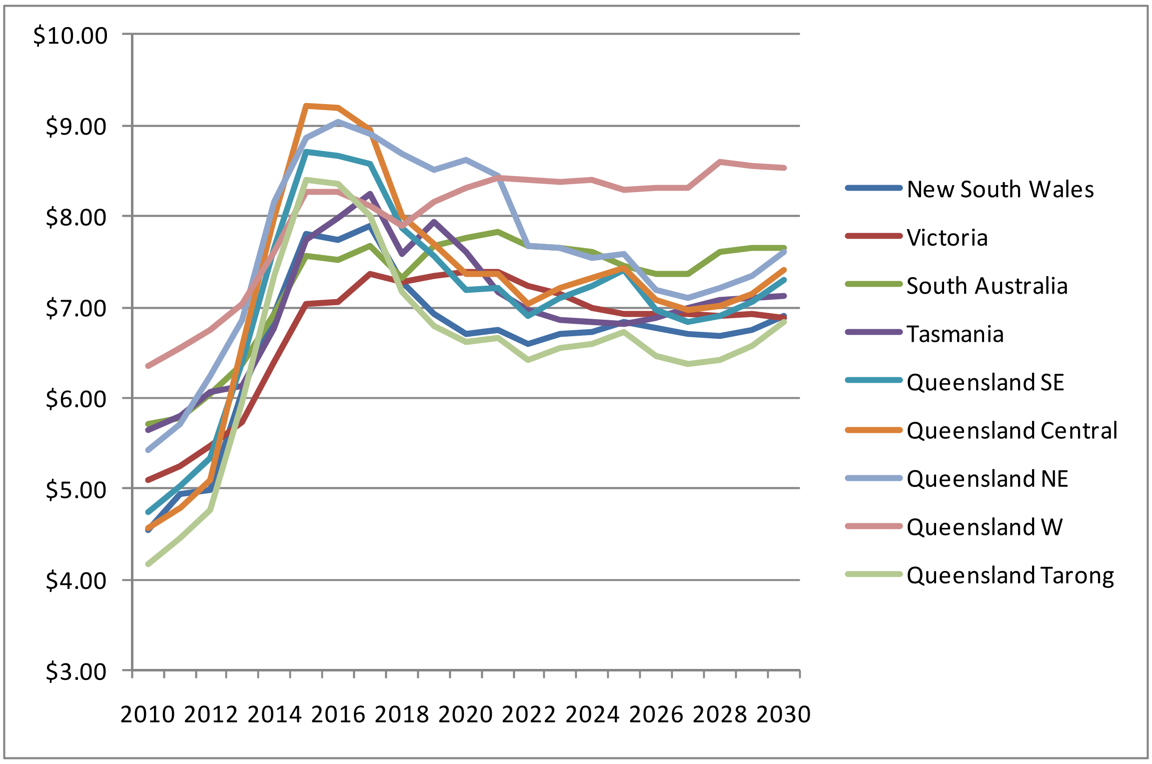


D.5 Gas price forecasts input into Strategist

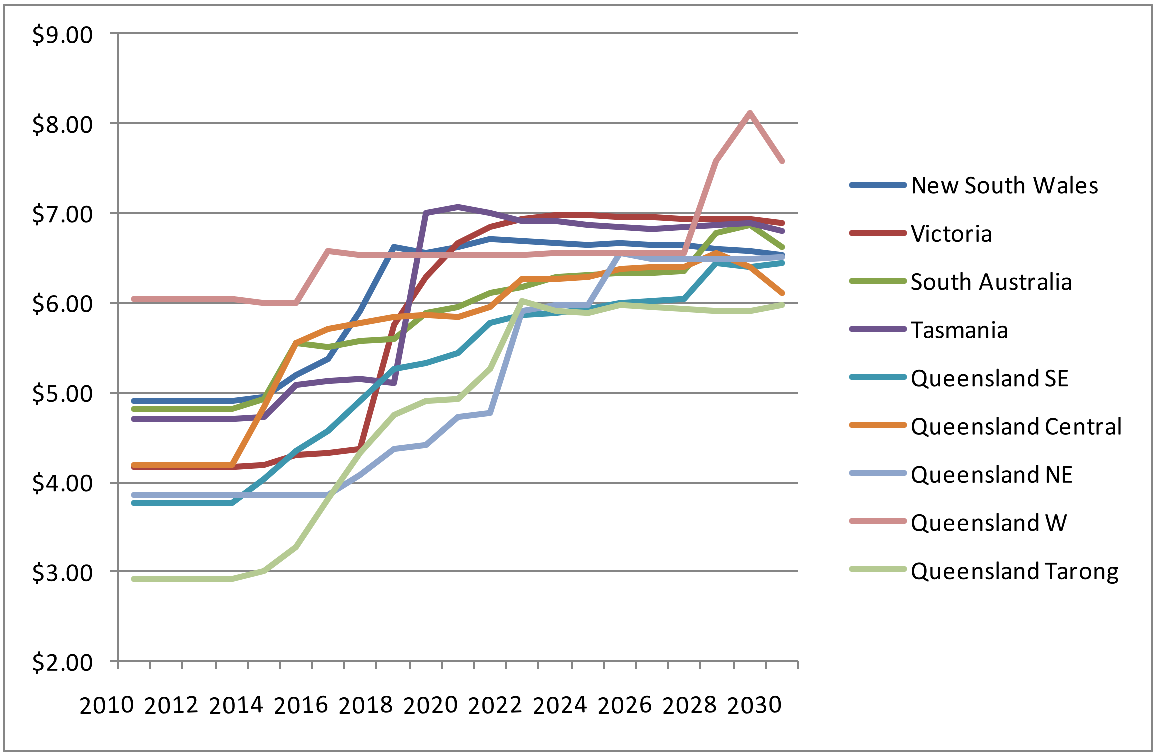
D.5.1 Medium gas price

The gas prices for the medium scenario derived from the MMAGas model actually input into Strategist by NEM region are presented in the charts below. Figure 67 shows gas costs for new entry plant throughout the forecast period. Similarly, Figure 68 shows the average cost of existing gas contracts, which represents the gas cost for incumbent plant throughout the forecast period. The corresponding table are tabulated in Table 26 and Table 27.

▪ **Figure 67 Projected Medium New Contract Gas Prices for the Eastern States, $2012**



▪ **Figure 68 Projected Medium Average Contract Gas Prices for the Eastern States, $2012**



- **Table 26 Projected Medium New Contract Gas Prices for the Eastern States, $2012**

Base	Tas	SA	Vic	NSW	Qld SE	Qld C	Qld NE	Qld W	Tarong
2012	$5.80	$5.83	$5.24	$4.87	$4.93	$4.73	$5.57	$6.54	$4.36
2013	$4.98	$5.45	$4.56	$5.24	$4.83	$5.08	$4.82	$6.13	$4.23
2014	$6.29	$6.13	$5.68	$6.34	$7.62	$7.70	$8.35	$6.93	$6.86
2015	$7.55	$8.14	$7.51	$7.88	$9.13	$9.79	$8.36	$9.26	$8.98
2016	$5.64	$5.96	$5.49	$6.22	$6.81	$8.10	$8.34	$7.04	$7.08
2017	$5.98	$5.97	$5.79	$6.36	$7.03	$6.40	$7.12	$6.68	$6.43
2018	$10.22	$6.96	$7.52	$7.25	$7.67	$8.12	$8.02	$7.67	$7.27
2019	$8.04	$7.82	$7.74	$6.88	$7.26	$7.63	$7.59	$8.48	$6.88
2020	$7.36	$7.88	$7.30	$6.49	$6.93	$7.13	$8.21	$8.43	$6.41
2021	$7.45	$8.18	$7.60	$6.82	$7.39	$7.52	$8.58	$8.94	$6.81
2022	$6.78	$7.09	$7.03	$6.36	$6.27	$6.37	$6.42	$7.73	$5.92
2023	$7.55	$7.04	$7.08	$6.39	$6.11	$6.36	$6.38	$7.83	$5.84
2024	$7.37	$7.21	$6.97	$6.58	$6.83	$7.06	$7.17	$7.79	$6.39
2025	$7.18	$6.86	$7.01	$7.17	$7.63	$7.82	$7.93	$7.27	$7.18
2026	$7.35	$7.11	$7.14	$6.49	$6.27	$6.48	$6.40	$7.64	$5.90
2027	$7.34	$6.96	$7.02	$6.57	$6.19	$6.49	$6.42	$7.79	$5.91
2028	$7.07	$7.36	$6.99	$6.32	$6.54	$6.64	$6.80	$8.79	$5.93
2029	$7.25	$7.49	$7.08	$6.34	$6.64	$6.65	$6.91	$8.16	$6.05
2030	$6.86	$6.51	$6.76	$6.89	$7.45	$7.49	$7.70	$7.35	$6.91

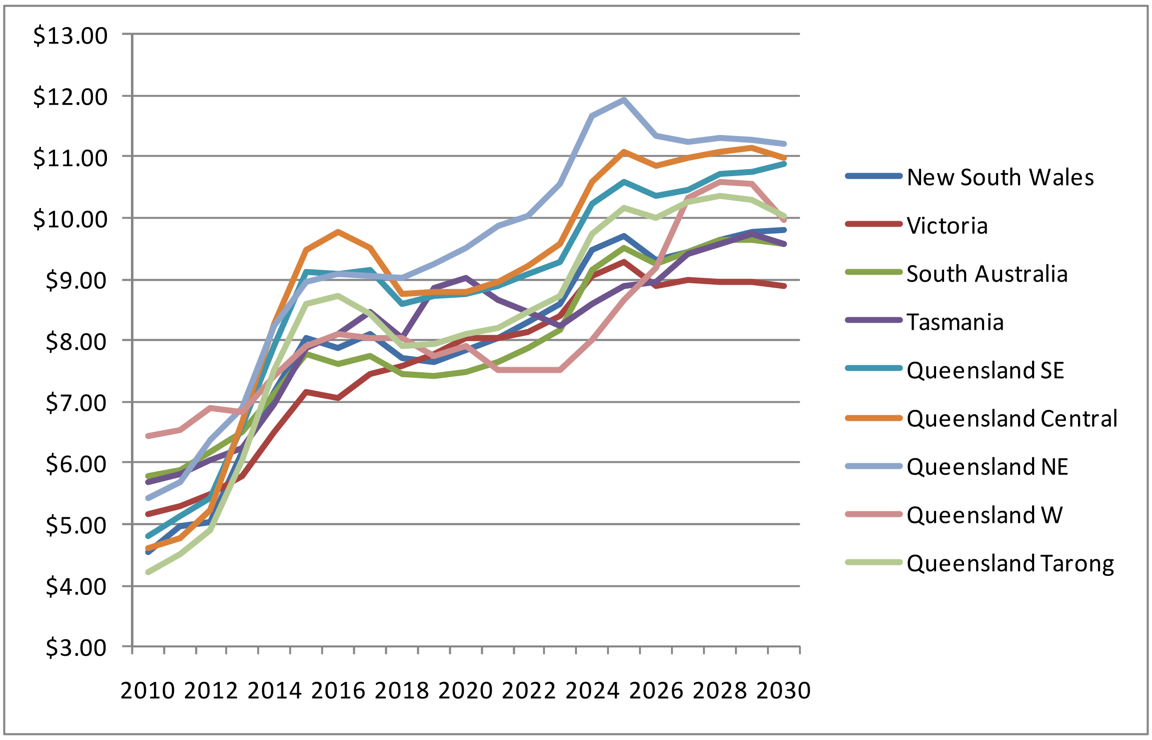
- **Table 27 Projected Medium Average Contract Gas Prices for the Eastern States, $2012**

Base	Tas	SA	Vic	NSW	Qld SE	Qld C	Qld NE	Qld W	Tarong
2012	$4.69	$4.83	$4.17	$4.90	$3.80	$4.17	$3.87	$6.05	$2.91
2013	$4.69	$4.83	$4.17	$4.90	$3.80	$4.17	$3.87	$6.05	$2.91
2014	$4.71	$4.91	$4.18	$4.95	$4.02	$4.90	$3.87	$6.01	$3.00
2015	$5.09	$5.49	$4.35	$5.24	$4.27	$5.50	$3.87	$6.00	$3.19
2016	$5.09	$5.48	$4.36	$5.37	$4.47	$5.82	$3.87	$6.34	$4.10
2017	$5.10	$5.52	$4.39	$5.69	$4.73	$5.80	$4.00	$6.34	$4.56
2018	$5.11	$5.58	$5.93	$6.48	$4.99	$5.79	$4.13	$6.42	$4.69
2019	$7.63	$5.95	$6.54	$6.51	$5.16	$5.90	$4.14	$6.46	$4.84
2020	$7.62	$6.05	$6.95	$6.59	$5.30	$5.90	$4.30	$6.47	$4.92
2021	$7.58	$6.17	$7.11	$6.70	$5.68	$6.05	$4.33	$6.51	$5.25
2022	$7.43	$6.25	$7.20	$6.70	$5.78	$6.37	$5.79	$6.51	$5.97
2023	$7.43	$6.36	$7.24	$6.66	$5.82	$6.36	$5.89	$6.51	$5.88
2024	$7.42	$6.37	$7.21	$6.65	$5.88	$6.40	$5.89	$6.51	$5.89
2025	$7.38	$6.39	$7.19	$6.65	$5.95	$6.48	$6.45	$6.52	$5.98
2026	$7.38	$6.41	$7.18	$6.64	$5.98	$6.49	$6.42	$6.52	$5.95
2027	$7.39	$6.42	$7.16	$6.63	$6.01	$6.49	$6.42	$6.52	$5.93
2028	$7.27	$6.81	$7.15	$6.58	$6.45	$6.64	$6.43	$7.37	$5.93
2029	$7.27	$6.90	$7.15	$6.55	$6.40	$6.46	$6.44	$7.84	$5.91
2030	$7.09	$6.65	$7.08	$6.49	$6.44	$6.20	$6.45	$7.60	$6.00

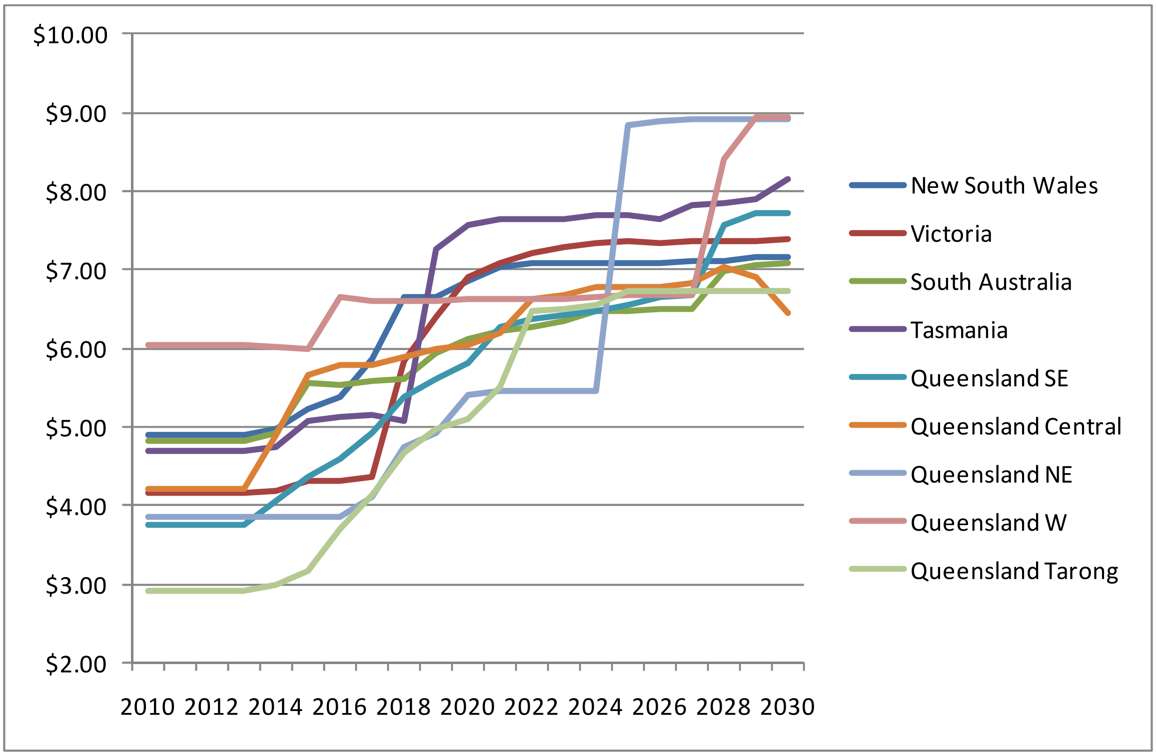
D.5.2 High gas price

The gas prices for the high gas price scenarios derived from the MMAGas model by NEM region are presented in the charts below. Figure 69 shows gas costs for new entry plant throughout the forecast period. Similarly, Figure 70 shows the average cost of existing gas contracts, which represents the gas cost for incumbent plant throughout the forecast period. The corresponding table are tabulated in Table 28 and Table 29.

- **Figure 69 Projected High New Contract Gas Prices for the Eastern States, $2012**



- **Figure 70 Projected Average Contract Gas Prices for the Eastern States, $2012**



■ **Table 28 Projected High New Contract Gas Prices for the Eastern States, $2012**

High LNG	Tas	SA	Vic	NSW	Qld SE	Qld C	Qld NE	Qld W	Tarong
2012	$5.76	$5.98	$5.27	$4.87	$5.07	$4.88	$5.68	$6.72	$4.50
2013	$5.09	$5.44	$4.52	$5.22	$4.99	$5.25	$4.81	$6.12	$4.41
2014	$6.56	$6.36	$5.81	$6.53	$7.75	$7.88	$8.38	$7.14	$7.05
2015	$7.60	$7.99	$7.31	$7.81	$10.12	$10.24	$8.36	$8.51	$9.43
2016	$5.61	$5.99	$5.24	$5.79	$7.32	$7.99	$8.33	$7.51	$7.60
2017	$6.16	$6.10	$5.79	$6.45	$7.24	$6.80	$7.21	$6.69	$6.54
2018	$8.83	$7.84	$7.42	$8.15	$8.86	$9.01	$8.93	$8.44	$8.12
2019	$9.52	$8.28	$8.92	$8.61	$9.40	$9.58	$9.53	$9.11	$8.59
2020	$8.99	$7.85	$8.48	$8.26	$9.23	$8.58	$10.11	$8.44	$8.56
2021	$8.14	$7.81	$7.40	$8.10	$8.99	$9.23	$9.23	$6.83	$8.44
2022	$7.91	$7.00	$7.22	$7.36	$7.85	$8.39	$8.42	$7.69	$7.71
2023	$7.98	$6.52	$7.21	$7.25	$7.50	$7.87	$7.89	$6.61	$7.17
2024	$9.05	$9.39	$8.80	$9.15	$9.78	$10.84	$11.37	$8.96	$10.01
2025	$9.42	$9.22	$8.78	$9.30	$8.67	$10.69	$11.48	$10.49	$9.68
2026	$8.02	$7.69	$7.32	$7.35	$9.08	$9.35	$9.64	$6.61	$8.56
2027	$9.69	$9.83	$8.92	$9.57	$11.05	$11.27	$10.78	$8.35	$10.45
2028	$8.37	$8.98	$7.80	$8.49	$10.64	$10.84	$11.43	$9.95	$9.94
2029	$8.39	$9.13	$8.25	$8.66	$10.51	$10.59	$10.71	$9.44	$9.68
2030	$9.71	$9.69	$9.09	$10.02	$10.61	$11.11	$11.70	$9.51	$10.60

■ **Table 29 Projected High Average Contract Gas Prices for the Eastern States, $2012**

High LNG	Tas	SA	Vic	NSW	Qld SE	Qld C	Qld NE	Qld W	Tarong
2012	$4.70	$4.83	$4.17	$4.90	$3.76	$4.20	$3.87	$6.05	$2.91
2013	$4.70	$4.83	$4.17	$4.90	$3.76	$4.20	$3.87	$6.05	$2.91
2014	$4.73	$4.92	$4.18	$4.98	$4.00	$4.93	$3.87	$6.02	$3.03
2015	$5.06	$5.48	$4.37	$5.23	$4.30	$5.53	$3.87	$6.01	$3.23
2016	$5.06	$5.47	$4.37	$5.33	$4.53	$5.77	$3.87	$6.45	$4.09
2017	$5.08	$5.52	$4.40	$5.64	$4.83	$5.77	$4.00	$6.44	$4.57
2018	$5.08	$5.58	$5.90	$6.66	$5.21	$6.02	$4.15	$6.48	$4.82
2019	$7.87	$6.11	$6.51	$6.78	$5.53	$6.09	$4.15	$6.56	$5.02
2020	$8.36	$6.24	$7.05	$7.03	$5.79	$6.15	$4.32	$6.61	$5.16
2021	$8.32	$6.37	$7.21	$7.25	$6.31	$6.33	$4.34	$6.61	$5.56
2022	$8.24	$6.43	$7.33	$7.32	$6.41	$6.79	$4.35	$6.62	$6.59
2023	$8.19	$6.50	$7.39	$7.31	$6.48	$6.84	$4.36	$6.62	$6.63
2024	$8.20	$6.57	$7.45	$7.34	$6.64	$6.90	$4.38	$6.68	$6.65
2025	$8.23	$6.58	$7.46	$7.36	$6.65	$6.89	$7.59	$6.70	$6.79
2026	$8.18	$6.60	$7.46	$7.36	$6.73	$6.88	$9.32	$6.69	$6.79
2027	$8.38	$6.60	$7.47	$7.39	$6.74	$6.93	$9.35	$6.70	$6.80
2028	$8.39	$7.06	$7.47	$7.39	$7.74	$7.13	$9.35	$8.48	$6.80
2029	$8.42	$7.21	$7.49	$7.45	$7.90	$7.07	$9.35	$9.02	$6.78
2030	$8.73	$7.23	$7.52	$7.49	$7.85	$6.75	$9.35	$9.04	$6.77

Appendix E Renewable Energy Models

E.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.

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[31]. This is assumed to be about $10 to $30/kW.
- 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-compliance, 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:

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[31] 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.

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.

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. Increase 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.

E.2 DOGMMA

E.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. We will calculate the premium based on market survey data and other published market data. The premium will be 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 will be 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.

E.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 A.1. 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.

Table 30: 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.

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.

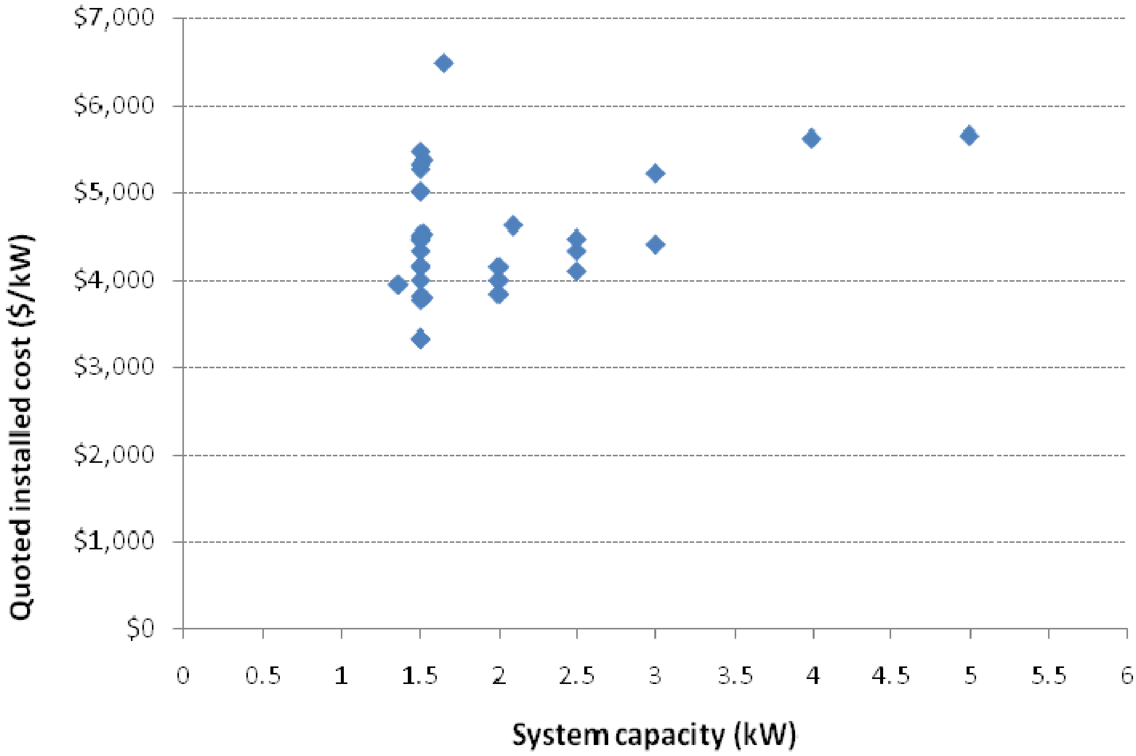
Unit capital costs are also assumed to decrease over time, reflecting long-term trends. Capital cost assumptions for 2012 are based on market research conducted by SKM MMA for a range of suppliers across Australia, and represents an average cost per kW including installation and before any Government 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 A- 1

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 71: 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:

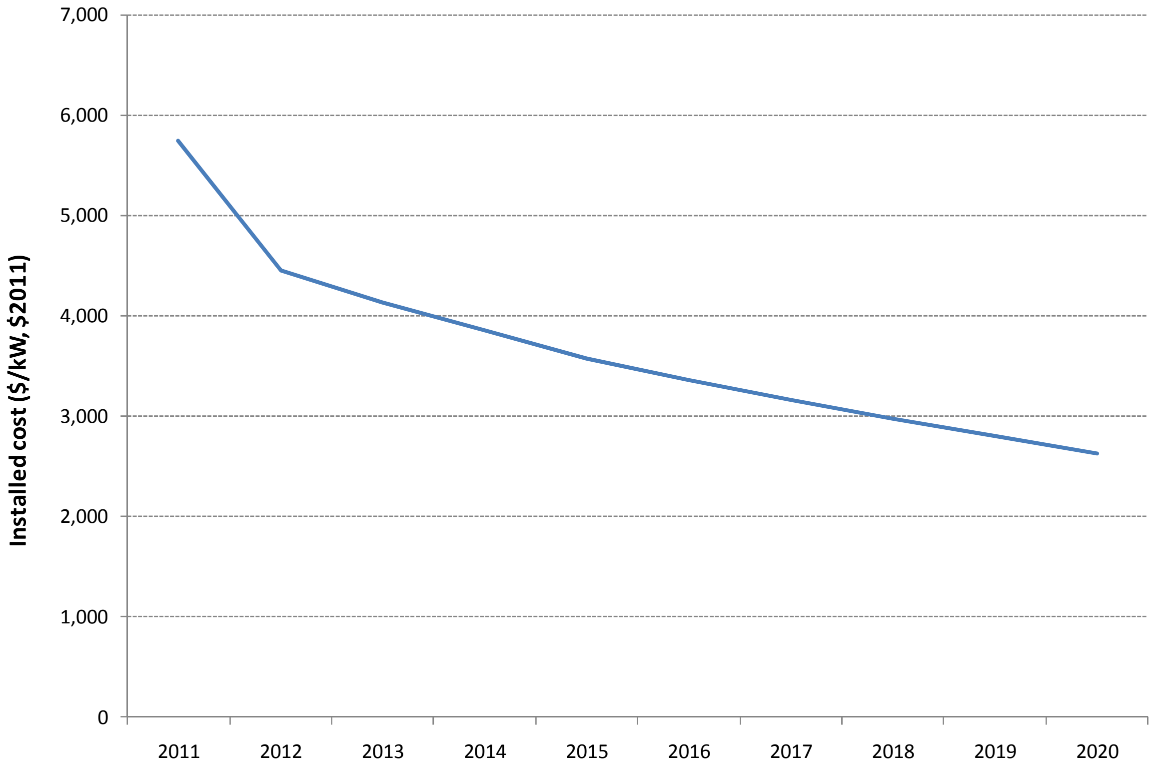
- Raw material cost.
- Other input costs.
- Economic conditions.
- Demand and production levels.
- Technology.

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 72.

- **Figure 72: 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

$4,500 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.

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