REVIEW

Australian Energy Market Commission

INTERIM REPORT

Impact of the enhanced Renewable Energy Target on energy markets

Commissioners

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Interim Report

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About the AEMC

The Council of Australian Governments, through its Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005. The AEMC has two principal functions. We make and amend the national electricity and gas rules, and we conduct independent reviews of the energy markets for the MCE.

Summary

The enhanced Renewable Energy Target (RET) is the primary policy of the Commonwealth Government to promote the growth and deployment of renewable energy sources in Australia. Under the enhanced RET there is a target of 45,000 GWh of electricity to be generated from renewable energy sources by 2020.[1] There is a 41,000 GWh target for large scale renewable energy such as wind farms (the Large Scale Renewable Energy Scheme) and a small scale renewable energy scheme for technology such as solar PV on residential properties (the Small Scale Renewable Energy Scheme), which has an aspiration but not a target of 4,000 GWh by 2020.

The Ministerial Council on Energy (MCE) has asked the AEMC to assess the impact of the enhanced RET on:

- The price of electricity for retail customers;
- The level of emissions; and
- The security and reliability of electricity supply.

The AEMC's Draft Interim Report was provided to the MCE on 8 July 2011. This finalised Interim Report includes updated modeling on the impact of the Small Scale Renewable Energy Scheme (SRES), to take into account recent changes to the Victorian, Australian Capital Territory, South Australian and Western Australian feed in tariff schemes. All other modeling results remain unchanged from the AEMC's July 2011 Draft Interim Report.

We have summarised our key findings below, with more detail about our analysis and conclusions in the main report and the accompanying reports from our consultants. The reference case modelled by the Commission is based on the continuation of policy settings as at late June 2011 and does not include a carbon emissions price. A carbon emissions price scenario has also been modelled, in addition to a counterfactual scenario, which assumes there is no enhanced RET. **Achieving the LRET target**

The modelling by NERA/ Oakley Greenwood forecasts that the target for the LRET will not be met, with a shortfall of about 35% by 2020/21 under policy settings as at late June 2011. Although in some cases retailers may choose to develop renewable energy projects or contract for Large Scale Generation Certificates (LGCs) even when it would appear to be more economic to pay the penalty (e.g. to obtain reputational benefits from being seen to meet the target), we doubt this effect would be large enough to substantially compensate for the forecast shortfall.[2]

The shortfall is driven by a lack of cost effective renewable energy projects. The economics of renewable energy projects have been adversely affected by an

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1 The target is for additional renewable generation compared to the average amount of renewable generation that was generated by power stations over 1994 to 1996.

2 Under the enhanced RET, Renewable Energy Certificates are now called LGCs and Small Scale Technology Certificates (STCs). The penalty price is $65 per LGC, but may have an effective maximum price of $93 after taking account of company tax treatment. The penalty price is fixed in nominal terms under the *Renewable Energy (Electricity) Large-scale Generation Shortfall Charge) Act 2000* (Cth).

unexpected over supply of Renewable Energy Certificates (RECs) mainly as a result of much higher than anticipated demand for RECs for residential solar PV systems under the previous expanded RET, increasing land use planning concerns about wind farms, and the failure of some technologies such as geothermal to develop as fast as was expected when the enhanced RET policy was being developed.[3] The extent of the shortfall is very sensitive to assumptions such as future gas prices and the availability and costs of future technology.

NERA/ Oakley Greenwood's modelling forecasts that the LRET would be met with a profile of carbon emissions prices similar to that considered at the time the Carbon Pollution Reduction Scheme (CPRS) was being developed. The carbon emissions price increases potential revenues available from the spot and contract markets, providing additional financial benefits to renewable energy projects on top of the price of LGCs.

Wholesale prices

The LRET will act to dampen wholesale electricity prices by increasing renewable generating capacity beyond the quantity that would have been developed without the additional revenue streams provided by the LRET to renewable generation. These additional revenue streams allow renewable generators to bid in a manner to ensure dispatch, which affects spot market outcomes.

Figure 1 below shows the forward electricity wholesale price curve that was modelled under the continuation of policy settings as at late June 2011 out to 2030/31. In most States and for most of the time until about 2025/26 to 2030/31 the wholesale price of electricity is below the long run marginal cost of new baseload gas fired power stations, meaning that there is no incentive for such power stations to be developed over this period.[4]

As the LRET directly impacts the revenues available to non-renewable generators from the wholesale market, it may have broader impacts on the reliability of supply (discussed further below). While depressed wholesale prices could undermine reliability of supply for consumers, some consumers are also unlikely to receive the benefit of lower wholesale prices, as the LRET creates a wedge between wholesale prices and the retail prices paid by consumers. In addition, consumers would pay for the cost of LGCs through their retail prices, to fund the additional revenue source for renewable generators.

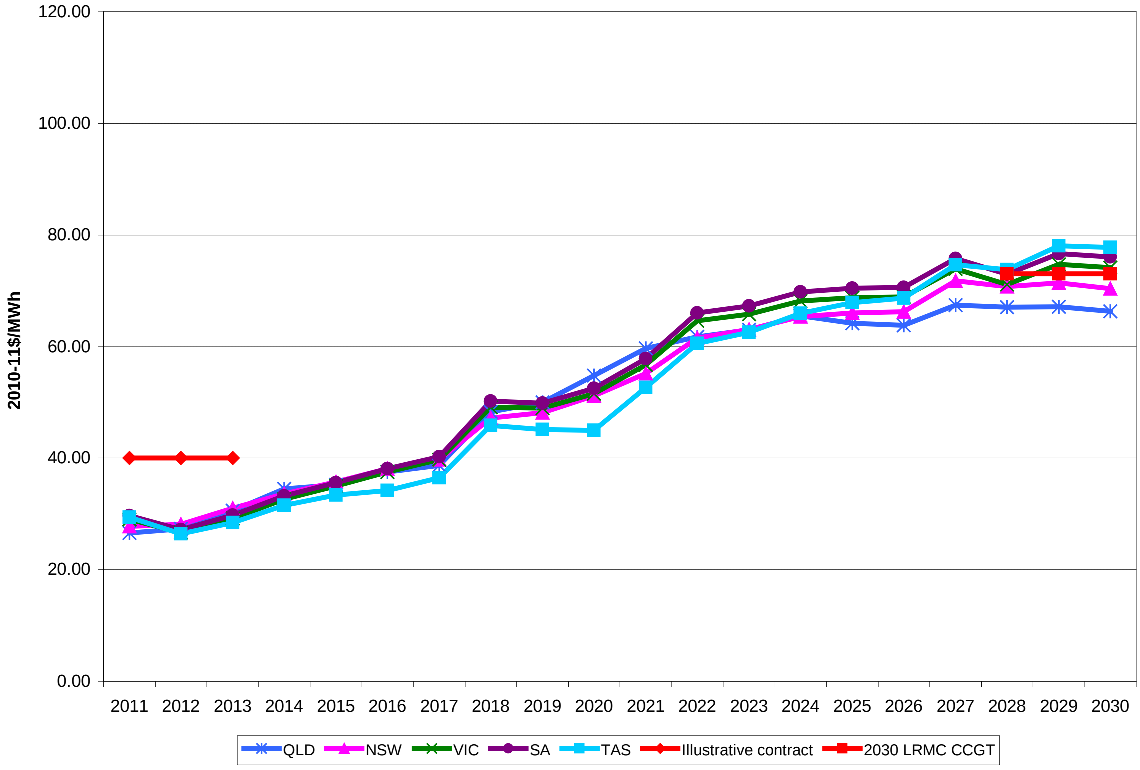
It should be noted however, that contract market dynamics have not been explicitly considered in our modelling, which may drive more investment, or result in investment earlier than forecast. However, in the medium to long term we doubt that a significant contract premium above the long run marginal cost of new generation would be sustained, as in this case it would be more cost effective for retailers to build

3 The expanded RET was the predecessor policy to the enhanced RET. Under the expanded RET there was a single target for large and small scale renewable energy with RECs created by both types of technologies.

4 Developers of generating capacity would need to have a reasonable expectation that their future revenues for the life of the investment would exceed the long run marginal cost of the technology before making an investment.

their own generation. Currently, contract prices are significantly above pool prices as shown in Figure 1 below.

Figure 1 Forecast profile of wholesale prices in the NEM under policy settings as at late June 2011



Note: Data represents financial years (e.g., 2011 is 2011/12)

The Small Scale Renewable Energy Scheme

The future take-up and costs of the SRES are difficult to forecast as take-up is influenced by a range of particularly uncertain factors, including the future path of retail electricity prices, the future cost of solar PV technology and the future policy settings for the SRES itself and State determined feed-in-tariffs (FiTs). We have modelled a number of scenarios and tested the sensitivity of our conclusions for key variables to partly address these forecasting difficulties.

Notwithstanding the difficulties of forecasting the future take-up of the SRES a number of key trends can be seen including:

- Take-up is very sensitive to the level of the Commonwealth Government's Solar Credits Multiplier. Take up under the SRES is forecast to reduce significantly as the multiplier reduces in the coming years. Historical take-up has also been very sensitive to the level of State determined FiTs.
- Assuming announced caps for jurisdictional FiTs are adhered to, the take-up of the SRES will fall markedly compared to levels as at late June 2011, but forecasts

of higher retail electricity prices and reductions in the technology costs for solar PV will still provide incentives for some consumers to take-up the SRES.[5]

- As the direct cost of uptake under the SRES is paid by all energy customers in the year an installation is registered, the direct cost for energy consumers of the SRES is likely to fall significantly in the coming years as take-up falls. However, energy consumers will continue to pay the costs of State FiTs for the installations that have already occurred as a result of the combined incentives provided by the SRES and jurisdictional FiTs. Based on policy settings for the SRES as at late June 2011 and current FiT settings we estimate the cumulative costs of the SRES could be $4.40 billion in nominal terms by 2020 across Australia.
- As the SRES is a national scheme, the decisions made by jurisdictional governments in relation to the design of their FiTs have an impact on the costs of the SRES for all consumers. This occurs as the number of installations that are made as a result of incentives under the SRES and jurisdictional FiTs in each year have a direct impact on the amount of certificates that retailers are required to purchase the following year. The cost of these certificates is then passed through to all consumers in Australia.
- Implicit subsidies are also provided to solar PV installations as installations reduce the base of energy use over which network tariffs are recovered, which transfers the largely fixed costs of maintaining the network onto energy users that do not have PV systems.

We are forecasting that by 2020 a total of 6,390 GWh of electricity would be displaced under the SRES when the impact of both the SRES and jurisdictional FiTs are taken into account. This is comprised of 3,170 GWh from solar PV installations and 3,220 GWh from solar hot water installations. This is 60% higher than the aspiration of 4,000 GWh by 2020 when the enhanced RET policy was put in place, and implies a penetration of solar PV to 27% of eligible houses in Australia by 2020.[6] When the effect of jurisdictional FiTs is removed, it is forecast that 4,431 GWh of electricity would be displaced by 2020 as a result of the SRES, which is 11% higher than the SRES' aspiration of 4,000 GWh.[7] Our forecasts take into account recent changes by the Commonwealth Government to the Solar Credits Multiplier and by jurisdictional governments to FiT rates and caps .

We have also undertaken some initial analysis to understand the characteristics of energy consumers who are benefiting from the SRES and those that are not. This analysis by Seed Advisory suggests that energy consumers in detached and semi-detached houses, between ages 35 and 74, with children and living in relatively low population density areas are major beneficiaries from the SRES. In contrast, younger people, those renting, people in higher population density areas and the very affluent

5 The FITs in Queensland and Western Australia currently do not have any cap.

6 We have calculated this figure as a percentage of detached and semi-detached houses. While we acknowledge that some terraced houses and flats may be able to install solar PV, it is likely to be a small minority.

7 However, we note that it is difficult in practice to isolate the net effect of the SRES, as consumers install small scale renewable technologies as a result of the cumulative effect of incentives provided under both the SRES and jurisdictional FiTs.

have not benefited. Our analysis of these distributional issues is only preliminary and we consider that future policy development could be informed by further work. As our analysis is at a postcode level, a survey of energy consumers who have installed solar PV systems may assist to further inform our initial analysis.

Reliability of supply

Our modelling indicates that there may be difficulties in meeting the target for unserved energy in the National Electricity Market (NEM) in most States over the period to 2020. This is because the LRET depresses wholesale pool prices, which reduces the primary source of revenues for non-renewable generators (who do not benefit from LGC prices). Consequential reductions in operating hours for baseload and peaking gas fired generation, combined with projected higher gas prices, mean that with market and policy settings as at late June 2011 (in particular the market price cap and cumulative price threshold) it is not economic for sufficient new gas fired generation to develop to meet the unserved energy target.

While our results indicate the potential for the reliability standard to not be met, further detailed analysis should be undertaken to assess the magnitude of this issue as the forecast level of unserved energy was not the primary focus of the Commission’s assessment. It should also be noted that as the reliability of supply is expressed as a very small proportion of time when demand may not be met, there is the potential for a margin of error to arise in our modelling which may affect forecast outcomes.

The magnitude of the level of unserved energy is also sensitive to the policy settings for any price on carbon emissions that is introduced, contract market dynamics, and key assumptions such as future gas prices. Where gas prices are higher than the mid range gas prices that have been assumed, there is the potential that the profitability of peaking gas fired generators may be further reduced which would increase the forecast level of unserved energy.

Security of supply and transmission impacts

The modelling undertaken for this study to assess the potential impacts of the LRET on the cost of maintaining security of supply show that such costs are unlikely to be material. However, such analysis is inevitably subject to considerable uncertainty, so it will be appropriate to continue to monitor these issues.

ROAM Consulting has forecast that while the requirement for regulation Frequency Control Ancillary Services (FCAS) in the NEM is set to increase significantly from current levels, it is nonetheless anticipated to only make up around 8% of overall RET costs by the end of the outlook period, and less than 2% of total energy revenues.

We expect that provided there are no barriers to new entry that FCAS markets themselves will keep the costs of FCAS manageable in the NEM, as higher prices in FCAS markets should encourage an increased provision of the relevant FCAS service. The AEMC notes in this regard that in Western Australia a more competitive market for Load Following Ancillary Services (LFAS) will be implemented shortly. Further, causer pays arrangements should help ensure that wind generators manage their impacts on the transmission system, although it should be noted that under a causer pays model these costs may become significant for wind generators by 2020.

Any increase in Network Support and Control Ancillary Services (NSCAS) costs specifically due to the LRET is expected to be small. This is in part due to the strict connection standards in South Australia, which are forecast to result in no additional NSCAS due to the LRET in that state. Further, decreasing costs and technological innovation mean that new wind generators connecting elsewhere in the NEM are increasingly likely to be the types that can either provide NSCAS such as reactive and voltage control, or at a minimum not increase the requirement for these services.

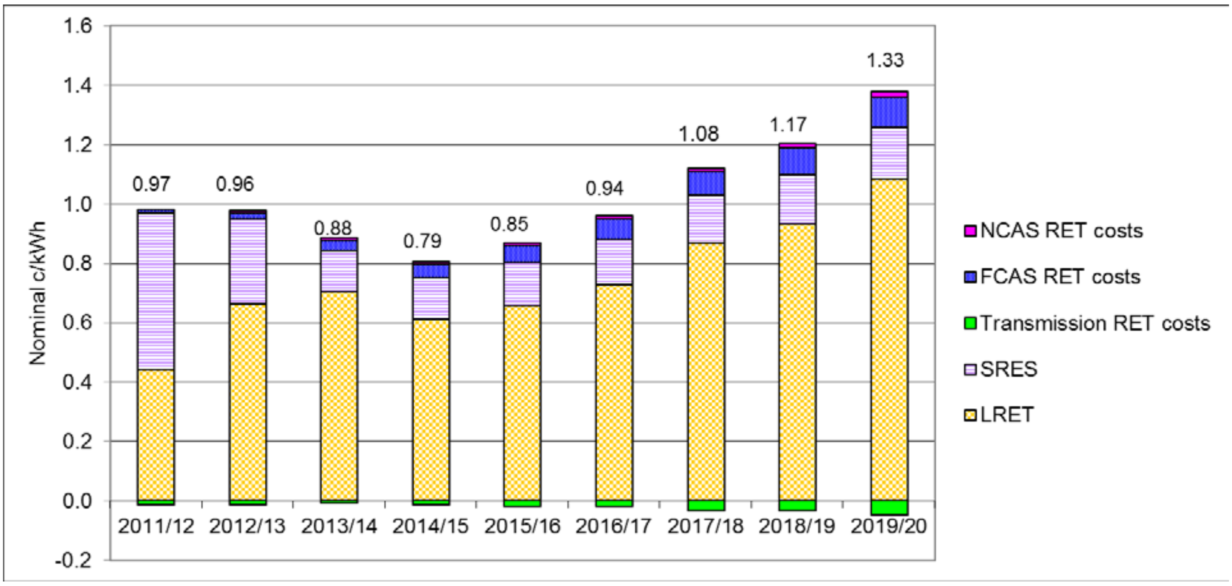
Our findings on the potential transmission impacts of the LRET show that these are expected to be small. We found little difference in overall transmission costs between the reference case, where the LRET was enforced, and the counterfactual, where there was no LRET. It appears that it is forecast demand growth rather than the LRET that is likely to drive future transmission investment requirements.

Impact on retail prices

Drawing together our analysis of the LRET and SRES allows us to estimate the costs for consumers of the enhanced RET up to 2020. Figure 2 below outlines our projection of the amount that the enhanced RET will cost residential customers over the outlook period. The total cost of the enhanced RET is forecast to increase by 37% in nominal terms from 0.97c/kWh in 2011/12 to 1.33 c/kWh in 2019/20. The cost of the RET is forecast to comprise 3-4% of the total retail electricity price over 2011/12 to 2019/20.

The LRET is expected to comprise around 74% of total RET costs for most of the outlook period. The cost impact of the SRES is forecast to decline significantly from 2012/13 onwards as uptake falls. Costs associated with security of supply impacts will remain relatively low over the outlook period. Under the enhanced RET transmission costs are forecast to be lower compared to if the RET was not in place as renewable generation is modelled to locate close to the existing transmission network.

Figure 2 Forecast costs of the enhanced RET in the NEM



Carbon emissions levels

We are forecasting that total carbon emissions from electricity generation will be around 250 Mt CO2-e in 2020/21 under the reference case, where a carbon emissions price is not assumed. This is around 5% lower than carbon emissions would have been without the enhanced RET. Total abatement under the enhanced RET over 2012 to 2020 is forecast to be 75.3 Mt CO2-e compared to if the RET was not in place. The LRET is expected to comprise 82% of total expected abatement, while the SRES is expected to comprise 18%.

For the overall enhanced RET, we estimate that the average cost per tonne of carbon emissions abated (t/CO2-e) would be around $185 by 2020 in 2010/11 dollars. There is a substantial difference between the abatement costs for the LRET and SRES, with the LRET being about $55 to $80 per t/CO2-e compared to about $300 to $500 per t/CO2-e for the SRES in 2010/11 dollars.

The modelling by our consultants forecasts that under both the LRET and SRES, renewable generation will often not displace the highest emitting plant in the NEM (coal fired generation, and particular brown coal generation), but will instead often displace gas fired generation. The effect is particularly pronounced for residential solar PV, which generates during the daytime hours, so will often displace mid-merit gas fired plant. Baseload coal plant would continue to generate including during the night when solar PV does not generate.

Conclusions and recommendations

From our analysis to date we can draw a number of conclusions about the impact of the enhanced RET. Our initial conclusions are:

- Under policy settings as at late June 2011, there is a significant risk that the enhanced RET target will not be met by 2020, without a price on carbon emissions.
- The LRET is forecast to suppress wholesale prices, which reduces the profitability of peaking gas fired generators. This may lead to a risk that the target for unserved energy in the NEM may not be met in a number of States over a number of years.
- There is a risk that consumers may not receive the benefit of lower wholesale prices, as the LRET creates a divide between wholesale prices and the retail prices paid by consumers. In addition, the compliance costs for customers of the LRET will be high because LGCs will trade at or close to the penalty price for a material proportion of the scheme's life due to the forecast shortfall in the LRET.
- Although the direct costs of the SRES for customers are expected to fall considerably in the coming years, there will be a substantial legacy cost for customers as a result of the already committed cost of jurisdictional FiT schemes.
- The relative abatement cost of the LRET is substantially lower than the SRES, suggesting it offers much better value for money.
- There are likely to be some increased costs for additional ancillary services requirements. While these costs are not large in the context of the overall costs of

the enhanced RET, it may be appropriate to consider options to better target and mitigate these costs.

The Commonwealth Government has committed to a review of the enhanced RET policy next year. We consider that our analysis to date identifies a number of issues that would merit consideration in that review, including:

- The design of the SRES – Its current design and uncapped nature means that it is very difficult to forecast its impact and costs. This has led to a number of changes to the policy settings, undermined the achievement of the LRET target and led to unexpected price increases for energy consumers.
- The aim of the LRET – Our forecasts suggest it is unlikely that the target for the LRET will be met without a carbon emissions price.[8] Increasing the penalty price would allow more renewable generation to be profitable, but would increase costs for consumers, further reduce wholesale prices, and may lead to higher levels of unserved energy.
- The design of jurisdictional FiT schemes – There is currently no common framework for setting FiTs. We believe there would be merit in the MCE developing a common framework for setting FiT schemes based around the costs avoided by installing solar PV, while the setting of the tariff rate and cap for the scheme could remain a jurisdictional responsibility.
- The beneficiaries of the SRES – It is not clear whether the Commonwealth Government had a particular view or intention about which types of consumers would benefit from the SRES, and which types of consumers would fund the SRES. Our initial analysis suggests that certain groups of consumers are benefiting much more than others.

[8] We have assumed a profile of carbon emissions prices based on those considered by Commonwealth Treasury under the proposed Carbon Pollution Reduction Scheme.

Contents

1 Introduction

1.1 Purpose of this report

This report sets out the Australian Energy Market Commission's (AEMC's) interim advice to the Ministerial Council on Energy (MCE) on the likely impact of the enhanced Renewable Energy Target (RET) on energy markets.[9] Advice is provided on the likely impact of the enhanced RET on a national basis and for each jurisdiction on:

- The price of electricity for retail customers;
- The level of emissions; and
- The security and reliability of electricity supply.

The AEMC's Draft Interim Report was provided to the MCE on 8 July 2011. This finalised Interim Report includes updated modeling on the impact of the Small Scale Renewable Energy Scheme (SRES), to take into account recent changes to the Victorian, Australian Capital Territory, South Australian and Western Australian feed in tariff schemes. All other modeling results remain unchanged from the AEMC's July 2011 Draft Interim Report.

This report has been developed following consultation with the MCE Standing Committee of Officials (SCO), the Commonwealth Department of Climate Change and Energy Efficiency (DCCEE), the Office of the Renewable Energy Regulator (ORER), the Australian Energy Regulator (AER), the Australian Energy Market Operator (AEMO), and the Commonwealth Treasury

1.2 Policy context for the Commission's advice

1.2.1 The enhanced RET

The RET scheme was established by the Commonwealth Government to encourage additional renewable energy generation to meet the Commonwealth's commitment to achieving a 20% share of renewables in Australia's electricity supply by 2020. The RET scheme expanded the previous Mandatory Renewable Energy Target (MRET) of 9,500 GWh of renewable energy generation by 2010 to 45,000 GWh of renewable energy generation by 2020. The targets under the RET will be maintained until 2030 after which the scheme will end. Under the RET, renewable energy generators receive certificates for eligible renewable electricity which is generated.[10] Wholesale

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9 The MCE requested the AEMC provide this advice on 16 September 2010, under section 6(b) of the *Australian Energy Market Commission Establishment Act 2004 SA.*

10 Under the LRET, renewable power stations receive one certificate for one MWh of eligible renewable electricity which is generated above the power station's baseline. The baseline for each power station is generally the average amount of electricity that was generated by the power station over the 1994, 1995 and 1996 years. Power stations which generated electricity for the first time after 1 January 1997 have a baseline of zero. Under the SRES, one certificate is created for one MWh of renewable electricity which is generated by small generation units (unless the Solar Credits Scheme Multiplier applies) or one MWh of electricity which is displaced by the installation of solar hot water heaters.

purchasers of electricity (primarily retailers) then have a legal liability to obtain and surrender these certificates or pay the penalties for non compliance.

The enhanced RET commenced on 1 January 2011 when the RET was separated into two parts, the Large Scale Renewable Energy Target (LRET) and the Small Scale Renewable Energy Scheme (SRES). The LRET covers large scale renewable power stations such as wind, solar and hydro-electric power stations, amongst others. The LRET has annual targets under legislation which increase each year until it reaches a target of 41,000 GWh in 2020. The price of certificates under the LRET are determined by the supply of and demand for those certificates.

Small scale renewable energy projects, such as the purchase of eligible solar water heaters, small-scale solar PV panels and small wind and micro-hydro systems, are covered under the SRES. Unlike the LRET, the SRES does not have annual targets (although there is an aspiration for 4,000 GWh by 2020) and the price of certificates under the SRES are set at $40 (excluding GST) per a certificate.[11] Under the Commonwealth Government's Solar Credits Scheme, purchasers of eligible small scale solar photovoltaic panels, wind and hydro systems are also able to earn additional certificates under the SRES until July 2013.[12] A range of other Commonwealth and jurisdictional based schemes also seek to increase the uptake of small scale renewable energy generation and have an impact on take up rates under the SRES. Further details on the enhanced RET and Commonwealth and jurisdictional based renewable energy schemes can be found in **Appendix A**.

1.3 The Commission's scope and approach to providing its advice

1.3.1 Scope of advice

The issues that are considered within and out of scope of the Commission's assessment of the enhanced RET are as follows:

- **Jurisdictions considered:** The impact of the enhanced RET on all Australian states and territories, including Western Australia and the Northern Territory, has been considered. The impact of the enhanced RET on a national level has also been assessed.
- **Outlook period:** The focus of our analysis is up to 2020, which reflects the timeframe for the enhanced RET. However, when considering the impact of the LRET we have taken into account an outlook period of 2030 to ensure the overall costs of renewable technologies that will influence market participants' decisions are considered.
- **Schemes considered:** We have assessed the impact of both the LRET and the SRES. We have also considered the impact of Commonwealth and jurisdictional renewable energy support schemes, such as FiTs, on the take up rate for the

11 Certificates under the SRES are set at $40 (excluding GST) when purchased through the Office of the Renewable Energy Regulator's (ORER's) Clearing House. Certificates for the SRES may also be bought and sold on the open market, where the price is subject to supply and demand.

12 In May 2011, Minister Combet announced changes to the Solar Credits Multiplier which brought forward the reduction in the multiplier by one year. As a result, the effect of the multiplier is now scheduled to end in July 2013 rather than July 2014.

SRES. In our reference case, we have assumed that the currently announced settings for these schemes continue. Sensitivities which reflect possible changes in these schemes have also been modelled.

- **Carbon policy:** The modelled reference case does not include the impact of a price on carbon. However, a carbon emissions price sensitivity which is based on a -5% reduction on 2000 emissions levels by 2020 has been undertaken to assess the impact that a carbon emissions price may have on the level of renewable energy generation under the enhanced RET.

1.3.2 Approach to providing advice

In preparing our advice on the impact of the enhanced RET, we have undertaken our analysis separately for the LRET, SRES and security of supply issues. This approach reflects the different nature of the work streams and the different analysis required. However, we have ensured that the analysis for each work stream relies on consistent assumptions where appropriate and takes into account any interactions between the analyses. The separate pieces of analysis for each work stream have been brought together in this report to illustrate the total effect of the enhanced RET on retail electricity prices, emissions levels, and the security of supply.

Modelling has been undertaken to assess the quantitative impact of the LRET and SRES on electricity prices and emissions levels, and security of supply. Scenario and sensitivity analysis has been used to test the robustness of our conclusions to changes in key assumptions. The cost impact of transmission augmentations that may be required in response to renewable generation which is installed under the LRET has also been considered. In developing our modelling assumptions and scenarios we have had regard to other relevant work that has been completed to date on the potential impact of the enhanced RET, including work undertaken by jurisdictional governments and regulators and market participants. A summary of this work is contained in appendices.

2 Approach and modelling methodology

The main focus of our analysis is to estimate the impact of the enhanced RET given policy settings as at late June 2011. To provide additional analysis we have also considered prices and emissions levels without the introduction of the enhanced RET. This particularly allows us to consider the net abatement value from the enhanced RET compared to a counterfactual. We have also considered how outcomes may change with the introduction of a price on carbon emissions from mid 2012.

There have already been a number of studies to estimate the impact of the enhanced RET, although the focus of each study has been different. Given these previous studies we have sought to understand how our results differ from the earlier studies and the key drivers of differences. Some of the differences are a reflection of the different dates on which studies were undertaken, while other differences reflect modelling approaches or assumptions.

As it is for the MCE to decide whether to publish the conclusions of our review we have only consulted with stakeholders within Government entities. In addition to the Commonwealth and State Governments we have consulted extensively with AEMO, AER, DCCEE, Commonwealth Treasury, and the ORER.

2.1 Modelling methodology

To assess the impact of the enhanced RET on retail electricity prices and emissions levels we have undertaken separate LRET, SRES, and transmission and security of supply analysis to reflect the different nature of these work streams. The methodology that was used to assess each of these work streams is described below, with further detail available in each of the consultant reports. For all work streams, three main scenarios were modelled:

- A reference case scenario, which reflects the continuation of announced policy settings as at late June 2011, and provides the baseline to assess the impact of the enhanced RET. The reference case does not include a carbon emissions price. Amongst the key assumptions underpinning this scenario is mid range economic growth, capital costs, demand and gas price forecasts.[13] No new installations of coal plant (beyond committed plant as at late June 2011) have been assumed. This is to reflect the policy uncertainty about the pricing of carbon emissions that existed in late June 2011, which made it very difficult to finance and/or obtain appropriate approvals for new coal plant;
- A carbon emissions price scenario, which includes the same key assumptions and policy settings as the reference case with the addition of a price on carbon emissions from July 2012. The carbon emissions price trajectory reflects the prices modelled by the Commonwealth Treasury for the CPRS and has been based on a minus five per cent reduction on 2000 level emissions by 2020. For the LRET, an additional carbon emissions price scenario was also modelled which was also

13 Data has been sourced from work undertaken by AEMO for the Energy White Paper and the National Transmission Development Plan, which has been developed following industry consultation. Data has been based on 'Scenario 3' inputs used by AEMO.

based on the trajectory for the CPRS, but had slightly higher prices between 2020 and 2030; and

- A counterfactual scenario, which assumes there is no expanded RET or price on carbon emissions over the outlook period. Committed levels of renewable plant are capped as at late June 2011, however existing jurisdictional FiT schemes are assumed to continue.

The analysis undertaken for each work stream has been based on consistent key assumptions for the three main scenarios modelled. A number of sensitivities were also modelled by each consultant to provide an indication of the differences in outcomes when different assumptions were applied.

2.2 LRET

Modelling the impact of the LRET on energy markets was undertaken by NERA Economic Consulting and Oakley Greenwood. The impact of the LRET in the NEM was modelled using market offers to determine optimum bid prices for the level of demand and availability of generation. These bids were based on expected profit maximising generator market behaviour developed through game theory techniques. Dispatch was determined on a load block basis using market based prices. This approach ensures that new entrants will recover their expected costs (including direct transmission connection costs) over the long term, and that reliability standards for the NEM of 0.002% of unserved energy can be assessed. As a result, only investments which are considered to be profitable (i.e. market revenue is greater than capital and operating costs) have been assumed to occur.

Modelling of the WEM and the Darwin/Katherine Interconnected System has determined generation investment requirements to ensure that the reliability standards in each jurisdiction are met. The WEM capacity price has been based on the principles currently used by the Western Australian Independent Market Operator (WA IMO) which aims to set a capacity price which is based on the capital cost of peaking gas turbine plant.

The cost of new generation technologies has been sourced from AEMO, and is based on the published work by AEMO and the Commonwealth Department of Energy and Resources as part of the preparation for the Energy White Paper. Mid range demand growth projections have been assumed and have been provided by AEMO and the WA IMO for their respective markets. Mid range oil, gas prices and economic growth have also been assumed and are based on data provided by AEMO.

The banking of RECs (now called LGCs) has been considered, which has allowed for year to year flexibility in how investments are made to meet the LRET. However, the LGC market has not been explicitly modelled. Rather, we have estimated the level of additional LGC support required for renewable generators to remain profitable after taking into account the revenue these generators would receive from forecast wholesale prices. Renewable plant has been forecast to be installed where the level of LGC support required has been less than the penalty price. In other words, it has been assumed that renewable plant would be installed where their expected costs, after taking into account forecast market revenue, is less than the penalty price.

An additional carbon emissions price scenario was also modelled for the LRET, which was based on a carbon emissions price trajectory provided by DCCEE. This trajectory was also based on Commonwealth Treasury's modelling for the CPRS to achieve a minus five per cent reduction on 2000 level emissions by 2020. As the carbon emissions price trajectory out to 2020 in this scenario is very similar to the carbon emissions prices used originally by NERA/Oakley Greenwood, we have not reported the results for this scenario in detail in our report. Between 2020 and 2030, prices under this scenario increased at a higher rate than was assumed by NERA/Oakley Greenwood which has lead to slight differences in results from 2020 onwards. The results for the additional carbon emissions price scenario are outlined in further detail in NERA/Oakley Greenwood's report.

The results of the modelling are considered in Chapters 3 and 4.

2.3 SRES

Modelling of the impact of the SRES on retail electricity prices and emissions levels was undertaken by ACIL Tasman. The SRES seeks to promote the installation of two main types of small scale renewable technologies - small generating units (e.g. solar PV, micro hydro, wind, etc) and solar hot water heaters. Our analysis has focused on the technologies primarily driving changes in STC creation rates, namely solar PV and solar hot water heaters. The uptake of solar PV was modelled using a financial payback approach, which takes into account the retail electricity prices faced by households and businesses, the costs of the solar PV system, and any support mechanisms and ongoing assistance available to solar PV systems (e.g. Solar Credits Multiplier, jurisdictional FiTs, etc). This approach assumes that the net financial impact of installing small generating units will be the primary driver of uptake.

The uptake of solar hot water systems was modelled using a stock replacement model, which assumes that uptake will be driven by the replacement of existing hot water systems or the construction of new dwellings.

In addition to the reference, carbon emissions price and counterfactual scenarios discussed above, two additional sensitivities were modelled for the SRES. These sensitivities were an 'elevated uptake' scenario and a 'reduced uptake' scenario. Under the elevated uptake scenario for small generating units, it is assumed that a higher level of uptake under the SRES is promoted compared to currently announced policy settings, by relaxing caps and increasing tariff rates under jurisdictional FiTs. Under the reduced uptake scenario, it is assumed that current policy settings will be changed to reduce uptake, by reducing the Solar Credits Multiplier at a faster rate and reducing tariff rates and caps under jurisdictional FiTs.

For solar hot water heaters, elevated and reduced uptake scenarios have been based around high and low variations from historic estimates of construction rates and water heater technology substitution rates.

The results of this modelling are set out Chapters 3 and 4.

2.4 Transmission and security of supply

This aspect of the study determined the potential increases in FCAS, LFAS and NSCAS required in achieving the LRET by 2020. The extent to which the LRET influences the need for new transmission investment was also modelled.

Future FCAS costs were estimated by first determining one minute resolution wind and demand traces for the NEM and SWIS. The most extreme 1-2% of disturbances were analysed to assess the amount of regulation raise and lower services required to maintain frequency within required limits (using a system frequency model calibrated individually to each of the NEM and SWIS). This data was then input into a half hourly dispatch model to determine regulation FCAS and LFAS costs for the NEM and SWIS respectively. FCAS and LFAS requirements were forecast for 2009/10 and 2019/20 under the enforced LRET scenario. These two years were then compared to assess the increase in FCAS and LFAS requirements due to the LRET by 2020. Historical FCAS, LFAS and energy bids were used as an input for the 2020 forecast.

NSCAS services are generally procured directly from generators by AEMO and TNSPs or are provided by generators automatically as part of their connection requirements under the National Electricity Rules. The costs of NSCAS can vary substantially depending on the type of wind turbines installed and the locations of these wind farms. South Australia imposes technical requirements for wind turbines equal to more conventional generation technologies; it was therefore assumed that the LRET would not increase the requirement for NSCAS in South Australia

Elsewhere in the NEM and SWIS, there are less stringent technical standards in place for wind turbines. Consequently, the assumption was made that only generators of the older type (such as fixed speed induction) entered and located in the weaker parts of the grid. This assumption maximises the requirement for NSCAS, which therefore provides an upper level bound on NSCAS costs. In practice, given falling costs and technical innovation, it is likely that more advanced generation types would also increasingly connect in other regions outside South Australia.

To assess transmission costs, ROAM used the fixed generation planting scenario for the enforced LRET, provided by NERA/Oakely Greenwood, to determine a least cost transmission investment plan to deliver this energy to market. The enforced LRET scenario was compared with the counterfactual and carbon case to assess any differences in transmission investment costs between the scenarios, and thus obtain an estimate of transmission costs that might be considered solely due to the LRET.

Network augmentations were considered at the level of the 16 zones in the National Transmission Network Development Plan in the NEM, and to the zones defined in Western Power's Annual Planning Report in the South West Interconnected System (SWIS). Augmentations were modelled by size, location and timing.

Given the uncertainty around forecasting actual unit costs in transmission for a range of capacities and technology types, ROAM used assumptions of $500/kW and $1000/kW to test the likely bounds of transmission costs in the scenarios. It is likely that the overall costs of transmission will fall somewhere in this range.

The results of this modelling, with regard to the impact on retail electricity prices, are set out in Chapter 3. Security of supply issues are also discussed in further detail Chapter 5.

2.5 Additional analysis on historic uptake under the SRES

In addition to the three modelling exercises set out above, we also engaged Seed Advisory to undertake some initial analysis to understand the characteristics of energy consumers who live in areas where there has been a high take up under the SRES, and how this compared to the groups of customers who live in areas with low take up. Seed Advisory used information provided by the ORER on the historical take-up of the SRES and compared this to Census information, and other information about the demographic characteristics of the population to better understand the characteristics of customers who live in areas where there has been high take up.

As we discuss in Chapter 6, this initial analysis could be extended to increase its robustness. However, we believe it provides a useful initial insight and we set out some suggestions for further analysis.

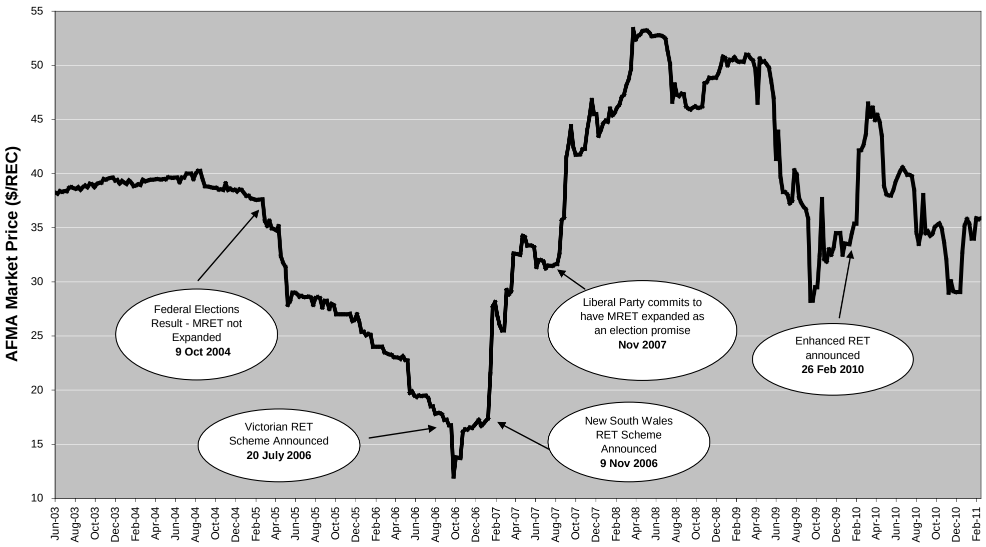
3 Impact of the enhanced RET on retail electricity prices

This Chapter sets out the Commission's finalised interim advice on the potential impact of the enhanced RET on retail electricity prices at a national and jurisdictional level. Costs relating to the enhanced RET as a result of the LRET, SRES, transmission investment, and maintaining security of supply have been modelled out to 2020.

3.1 Impact of the enhanced RET on retail electricity prices

Assessing the likely impact of the enhanced RET on retail electricity prices is complex, as the costs of the RET are highly dependent on future policy settings and expected capital and system costs for renewable investments. Changes in these factors are likely to result in significant variations in the level of forecast renewable generation and expected costs. Over recent years there have been a number of policy changes that have affected incentives for renewable investments. Figure 3.1 shows how the price of RECs has changed historically and the date of some of the key policy decisions that have affected the incentives for investment in renewable generation.

Figure 3.1 Weekly AFMA published REC prices - June 2003 to February 2011



Source: TRUenergy for the Investment Reference Group report

While the outcomes of the modelling undertaken for this review must necessarily be interpreted with some caution, due to the factors outlined above, we consider the overall conclusions of this review with regard to impacts on price, security of supply and emissions to be robust given the best available information. Comparisons with other studies, which we have outlined in Appendix B and C, also lend us confidence that our broad conclusions are robust.

3.1.1 Impact of the LRET on retail electricity prices

The LRET has annual targets set out under the *Renewable Energy Target Act (2001)* that increase each year until it reaches a target of 41,000 GWh by 2020. Wholesale purchasers of electricity (generally electricity retailers) are able to meet their annual liabilities under the LRET by purchasing LGCs or creating them through investments in large scale renewable generation. LRET liabilities may also be met by paying the penalty price where the cost of purchasing or generating LGCs is higher than the penalty price. The nominal penalty price currently has a cost of $65 but may have an effective cost of up to $93 when taxation is taken into account.[14]

It should be noted that some retailers may purchase LGCs even where the cost is greater than the penalty price (up to a certain point) because of reputational or brand reasons. However, the potential for this behaviour has not been included in our modelling given the complexity of modelling such behavioural factors.

The revenue that is earned by renewable generators is comprised of wholesale prices, LGC prices, and any additional contract premium that may be provided by retailers. In modelling the impact of the LRET and the likely level of future renewable generation we have modelled future wholesale prices. The LGC market has not been explicitly modelled in this study, nor have we estimated the influence of contract premiums on driving investment outcomes. Rather we have estimated future spot prices, and on the basis of these prices, we have calculated the level of LGC support (i.e. the difference between the renewable generator's expected costs and the revenue the generator earns from wholesale prices) that would allow renewable generators to recover their expected annualised costs.

Under this approach, renewable generators are forecast to be installed and dispatch their energy whenever the required LGC support for profitable renewable generators is less than the penalty price. This assumes that LGC prices will increase up to the penalty price, as where LGC prices are higher than the penalty price it would be more economic for retailers to pay the penalty to meet their liabilities.

LGC prices have been relatively low in recent months (see Figure 3.1 above) due to the overhang of certificates produced by the higher than expected uptake of small scale renewable technologies. There is a risk that our modelling approach may slightly overstate the forecast level of renewable generation investment in these early years of the outlook period due to the overhang of certificates. This may occur if LGC prices remain significantly lower than the penalty price.

In addition to the current overhang of certificates, other factors such as the level of banked certificates and strategic expectations of LGC and wholesale prices in the event of a carbon emissions price, may influence certificate prices, the expected revenue renewable generators may receive, and the likelihood that renewable generation is installed. These factors may create further volatility to LGC prices particularly in the early years of the outlook period.

Analysis of AEMO's recent Electricity Statement of Opportunity reports highlights that over the past three years there have been a limited number of renewable energy projects which have progressed from the publicly announced proposal stage. This may be related in part to uncertainty associated with likely future wholesale prices, LGC prices, and the availability of contracts.

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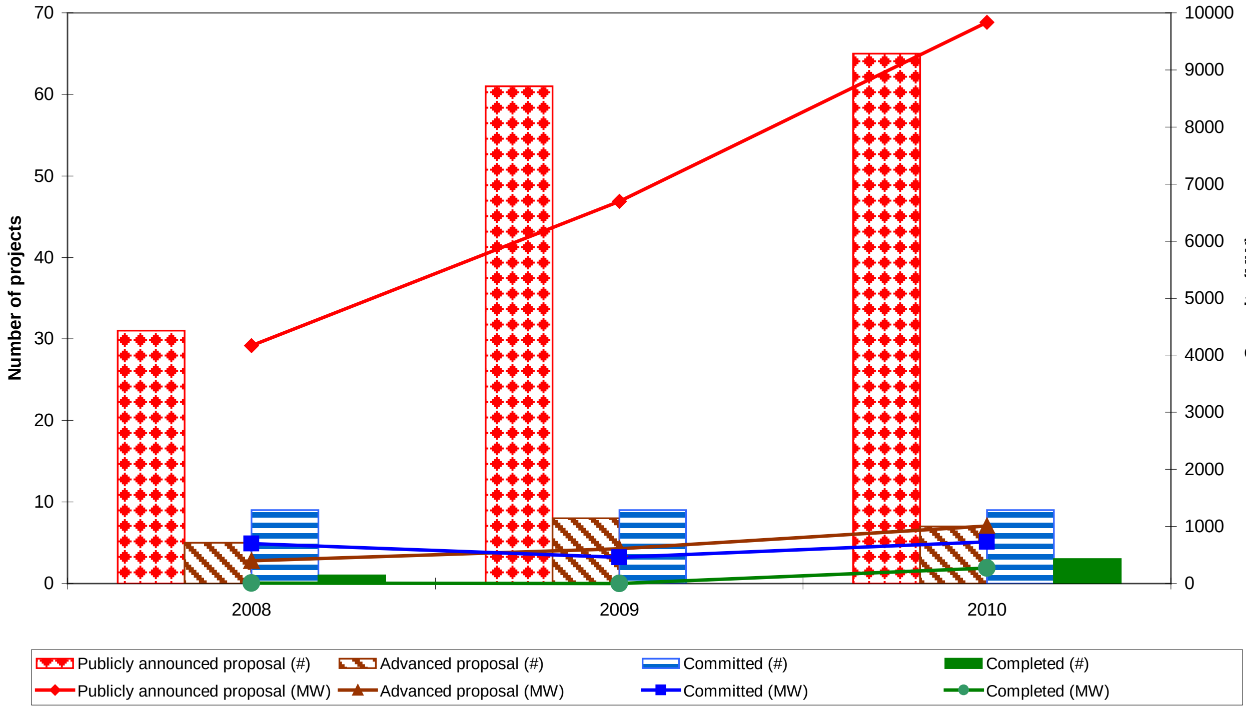
14 The penalty price is set out in the *Renewable Energy (Electricity) (Large-scale Generation Shortfall Charge) Act 2000* (Cth). In real terms the penalty price will fall over the life of the RET.

Figure 3.2 Upcoming renewable generation projects in the NEM



Source - AEMO Electricity Statement of Opportunities Report 2008, 2009 and 2010. 'Publicly announced proposals' meet less than three of AEMO's project commitment criteria, 'advanced proposals' meet at least three, and 'committed' projects meet all five of the criteria. Project commitment criteria include: purchase of land, contracts for plant/ equipment, planning and construction approval, financing, and the setting of a final construction date.

Although current LGC prices may reduce the profitability of renewable generators, this may in part be offset by contract premiums which may provide additional revenue for renewable generators on top of forecast wholesale prices. While a specific allowance for contract premiums has not been provided for in our modelling, it is likely that contract premiums would provide at most $15/MWh in additional revenue. However, we consider that in the longer term it is unlikely that a contract premium above the LRMC of new generation would be sustained as in this case it would be more cost effective for retailers to build new generation rather than contract.

Achievement of the LRET

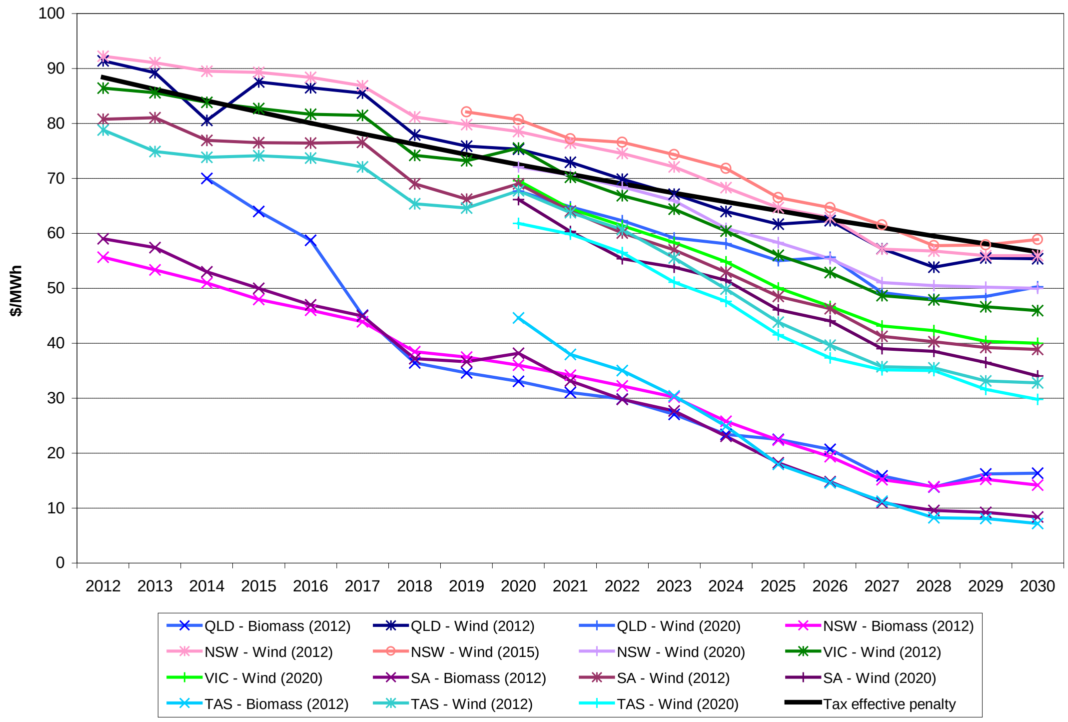
By 2020/21, under policy settings as at late June 2011, it is forecast that around 24,000 GWh of electricity will be generated under the LRET in the NEM as a result of around 4,200 MW of installed capacity above levels in late June 2011. This is approximately 35% below the NEM's pro rata share of the LRET by 2020. This forecast shortfall reflects policy settings as at late June 2011, including the lack of a price on carbon emissions, themarket price cap of $12,500/MWh and the penalty price of $65 which limits the combined revenues available from the spot and LGC markets.[15] It is forecast that the penalty price would need to be raised from $65 to between $75 and $80 in

[15] Under the AEMC's 'Reliability Settings from 1 July 2012' Rule 2011, No. 5, the market price cap will be indexed at the CPI from 1 July 2012.

nominal terms to bring forward sufficient additional renewable generation to meet the LRET by 2020. Figure 3.3 sets out the required LGC revenue required by different types of renewable generation to meet the LRET compared to the maximum tax effective penalty price.

Our conclusion that the LRET may not be met by 2020 without a carbon emissions price is consistent with the conclusions of modelling performed by AEMO for the National Transmission Network Development Plan (NTNDP). We also understand that SKM MMA's modelling for DCCEE indicated that the LRET would only be met if substantial geothermal generation was available before 2020, and since that study there appear to have been further delays in the development of cost effective geothermal generation.

Figure 3.3 Required LGC revenue required to meet the LRET compared to the penalty price



Note: Data represents financial years (e.g., 2011 is 2011/12

In Western Australia it is forecast that existing and committed renewable investments in the SWIS are likely to just meet the Western Australian pro rata share of the LRET by 2020/21. At this stage further analysis has not been undertaken to assess whether it is likely that additional renewable investment would be installed in the SWIS which could in part reduce the forecast shortfall in the LRET in the NEM. However, as the primary source of renewable technology that is committed to be installed in the SWIS prior to 2020/21 will be low inertia wind generation, it is likely that any additional renewable plant would create significant risks for the relatively small SWIS power system and so may not be viable.[16]

16 Low inertia generation plant requires higher and more costly levels of ancillary services to ensure system reliability can be maintained.

While, as we note earlier retailers may still invest in renewable generation projects at costs above the penalty price, it seems unlikely this effect would be large enough to make a substantial difference to the achievement of the LRET given the size of the forecast shortfall. It should also be noted that these results do not take into account recent requirements for new wind farms in Victoria to seek written consent from relevant residents where wind turbines will be within a 2km radius of residential homes. In addition, wind energy facilities have been prohibited from a number of locations in Victoria. [17] These requirements are likely to increase the resource costs of meeting the LRET as progressively less economic sites may need to be used, which would further reduce the level of future renewable generation. Our modelling indicates that following 2020/21, there is insufficient revenue for renewable generators to bring forward significant further renewable generation.

Where a carbon emissions price is assumed to be introduced in 2012, the LRET is forecast to be met by 2020/21 with a LGC price of as low as $10 in some years of the outlook period. The starting carbon emissions price in 2012 would need to be at least $20/t CO2-e for the LRET to be met. The LRET is met with a low LGC price as higher wholesale prices under a carbon emissions price are able to provide sufficient revenue to renewable generators to ensure they remain profitable. In contrast, without the enhanced RET or a carbon emissions price, the level of renewable generation is forecast to be 5,666 GWh by 2020/21. This highlights the need for ongoing financial incentives to make renewable generation economic against thermal generation, and that without such financial incentives the level of renewable generation is likely to remain flat over the outlook period.

As the outlook period for our modelling ends in 2030 to reflect the policy horizon of the LRET, results beyond 2020 should be treated with some caution. For investments which are forecast to occur following 2020, our modelling horizon may not fully take into account future revenues over the life of the investment. This may affect the modelled profitability of the investment, which may have implications for the overall level and type of investments which have been modelled from 2020 onwards. Given the policy horizon of the LRET, it will be the carbon price that increasingly drives investments in renewable energy beyond 2020 based on the cost effectiveness of different technologies.

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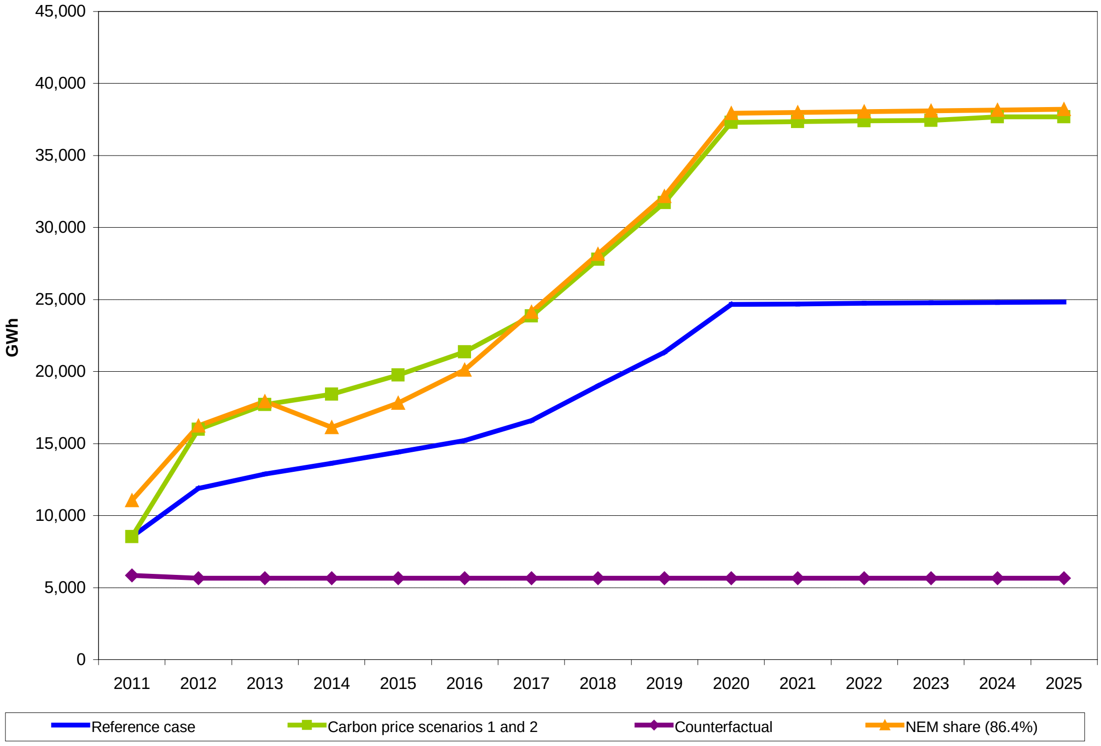
17 Further details on the new Victorian planning arrangements for wind energy facilities can be found here: http://www.dpcd.vic.gov.au/planning/planningapplications/moreinformation/windenergy#policy

Figure 3.4 Forecast renewable generation in the NEM by scenario



Note: Data represents financial years (e.g., 2011 is 2011/12)

Profile of generation investment

Under policy settings as at late June 2011, 4,200 MW of additional renewable generation capacity above late June 2011 levels is forecast to be installed by 2020/21. The installed renewable generation is mostly wind, with some biomass generation. However, as wind only generates on an intermittent basis it is assumed that wind will only contribute 3% of its installed capacity over peak periods in the NEM.[18]

Open cycle gas plant is forecast to be economic during the early years of the outlook period, with 7,000 MW installed across the NEM by 2020/21. 1,300 MW of additional closed cycle gas plant is also installed by 2020/21. Following 2020/21, gas plant continues to be installed with a further 4,600 MW of open cycle gas plant and 9,000 MW of closed cycle gas plant forecast by 2030/31. If coal plant had been an option, it is likely that some coal would have displaced some of the forecast closed cycle gas plant.

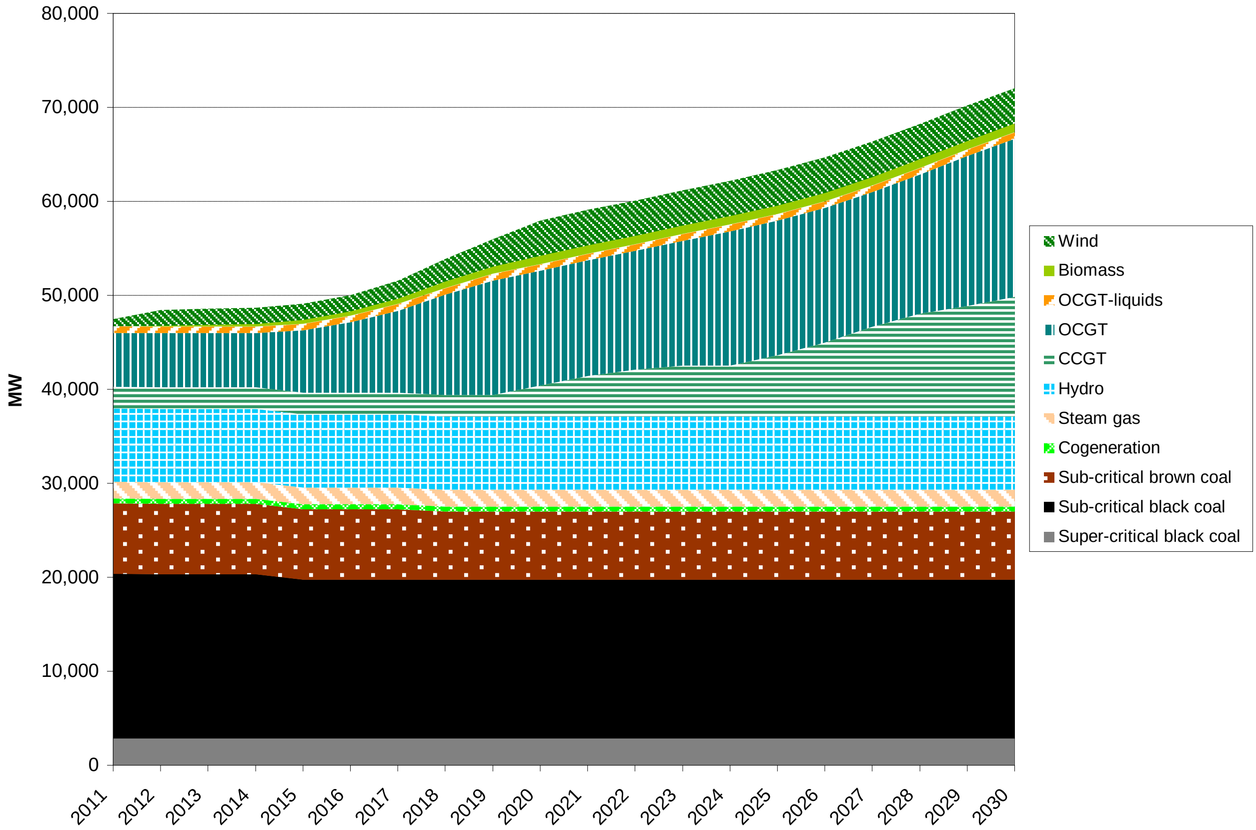
Under our carbon emissions price scenario by 2020/21 4,237 MW of additional renewable generation capacity is forecast compared to the reference case, which is comprised predominately of additional wind generation. This causes slightly less gas plant to be installed compared to the reference case. As well as increasing the profitability of renewable plant, higher wholesale prices with the inclusion of a low to moderate carbon emissions price also tends to increase the profitability of coal plant, since wind will tend to displace gas relative to coal. The profitability of coal only

18 This approach is consistent with that currently used by AEMO.

becomes significantly affected once a carbon emissions price lifts the costs of coal to such an extent that it replaces gas as the marginal plant. However, this does not occur for the period modelled in our study, given our assumptions on the carbon emissions price trajectory.

Under the counterfactual, the level of renewable generation capacity remains largely unchanged over the entire outlook period. However, significantly higher levels of gas plant (particularly closed cycle gas plant) are forecast to enter the NEM over the modelled period. This occurs as gas plant becomes more profitable in the absence of the renewable generation which is forecast under the LRET, which results in depressed wholesale prices under the reference case.

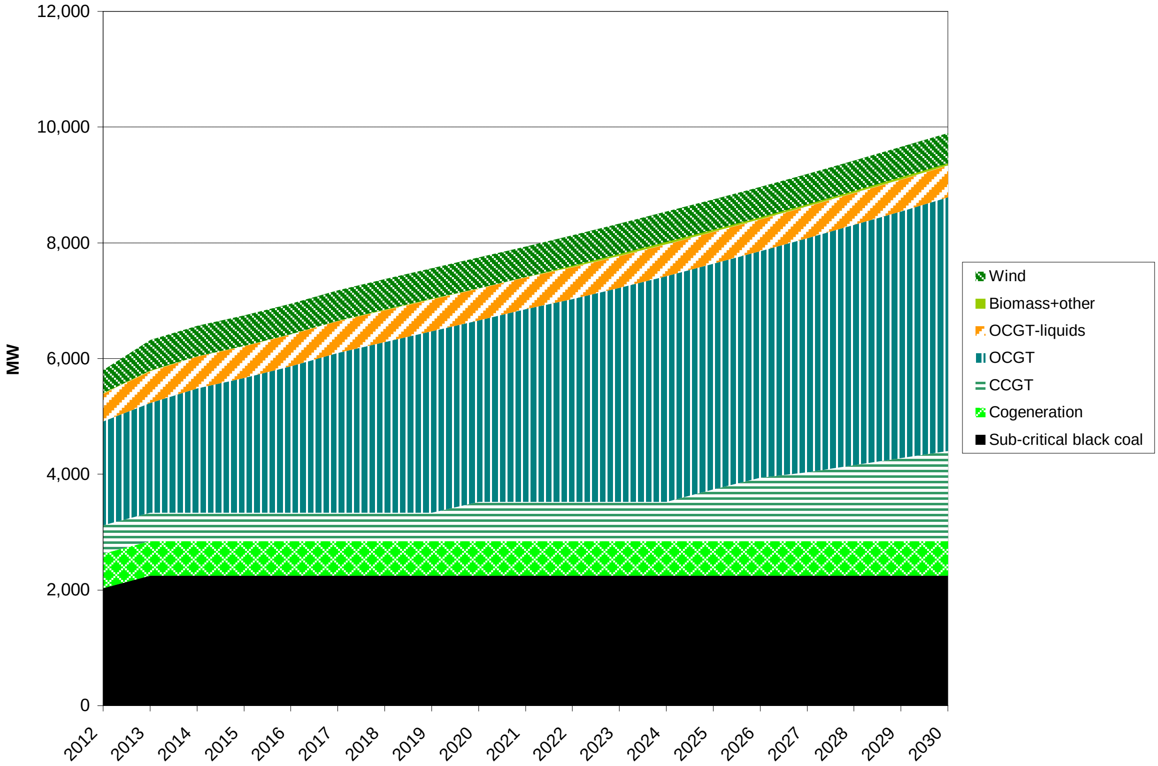
Figure 3.5 Forecast installed capacity in the NEM - Reference case



Note: Data represents financial years (e.g., 2011 is 2011/12)

In the SWIS under policy settings as at late June 2011 new investment in generation capacity is primarily wind and open cycle gas plant prior to 2020/21, with closed cycle gas plant being installed from 2020/21. The overall level of generation capacity in the SWIS is driven by the capacity reserve margin under the market rules. By 2020/21, 1,200 MW of open cycle gas plant and 180 MW of closed cycle gas plant are forecast to be installed, with a further 1,200 MW of open cycle gas plant and 900 MW of closed cycle gas plant forecast by 2030/31.

Figure 3.6 Forecast installed capacity in the SWIS - Reference case



Note: Data represents financial years (e.g., 2011 is 2011/12)

Impact on wholesale electricity prices

In modelling wholesale electricity prices, we have used a load block modelling approach which is useful for modelling trends in prices over the long term outlook period of this study but may provide less detail on likely short term price trends. We have also sought to model spot price outcomes rather than seeking to replicate the methodology used by jurisdictional regulators or retailers in setting the wholesale component of retail electricity prices, which generally also includes hedging and ancillary service components. For these reasons, our wholesale price forecasts may differ from other shorter term wholesale price forecasts set out by jurisdictional regulators or other modelling reports.

As well as differences in outlook periods and objectives, differences in modelling assumptions and methodologies can also contribute to differences in wholesale price forecasts.

The modelling shows that, given the continuation of policy settings as at late June 2011 (in particular the level of the penalty price), the LRET is unlikely to be met. This is largely because of an increasing volume of renewable generation capacity, which depresses wholesale electricity prices for a prolonged period of time. Lower wholesale prices depress revenues for non-renewable generation capacity, which do not obtain the benefit of an additional revenue stream from LGCs. This effect also depresses revenues for renewable generators. This occurs as depressed spot prices require an increase in the LGC price to allow the costs of renewable generators to be recovered.

However, rises in LGC prices are capped at the penalty price which falls in real terms over time.

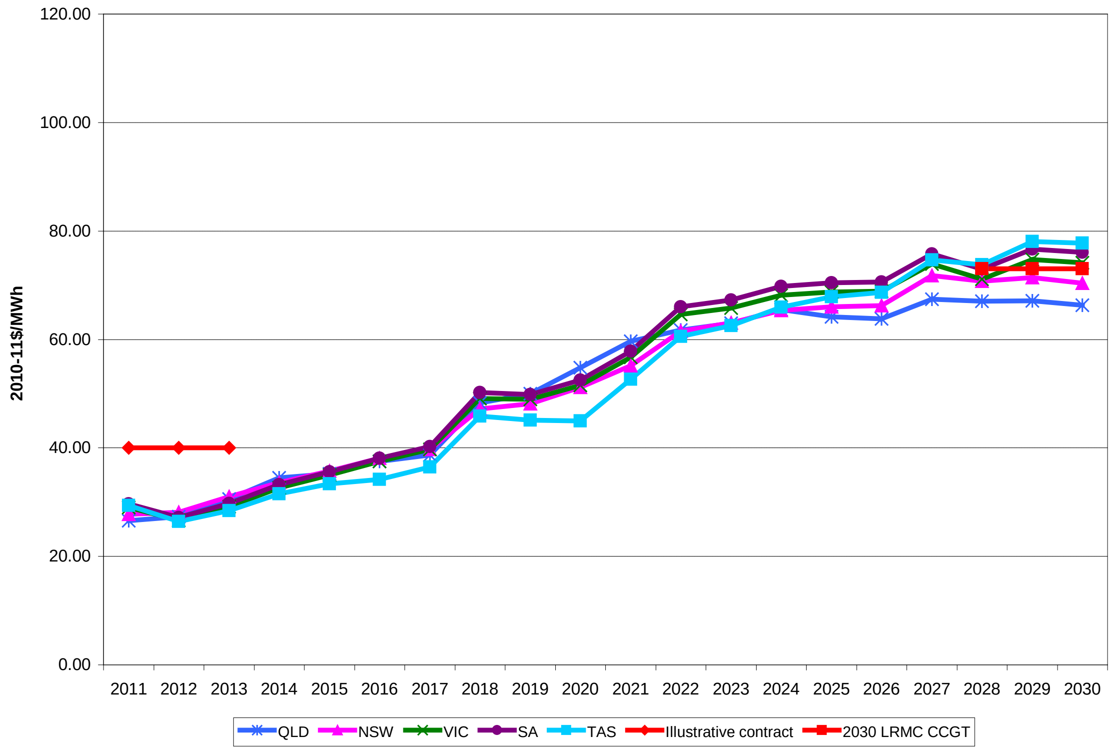
By 2020/21, it is forecast that wholesale prices in the NEM will be around $50/MWh in 2010/11 dollars under policy settings as at late June 2011. Wholesale prices are unlikely to return to the long run marginal costs for new base load gas plant until around 2025/26 to 2030/31. The anticipated growth in prices over the outlook period is being driven by a combination of factors, including anticipated increases in gas fuel prices and the cost of new investment requirements from 2020/21.

It is important to note that in practice contract prices are likely to dominate wholesale electricity purchase costs for retailers and therefore prices for consumers. Figure 3.7 shows current contract prices, which are underpinned by spot price expectations. A premium compared to spot prices is unlikely to be sustained above the long run marginal costs of new generation in the longer term.

The counterfactual scenario shows that if the LRET was not in place, wholesale prices are forecast to be around $10/MWh to $15/MWh higher by 2020/21 at around $60/MWh to $65/MWh in the NEM in 2010/11 dollars. This indicates the effect of the LRET in depressing wholesale prices. In the carbon emissions price scenario wholesale prices are forecast to be higher than under both the counterfactual and reference case at around $80/MWh in the NEM by 2020/21 in 2010/11 dollars.

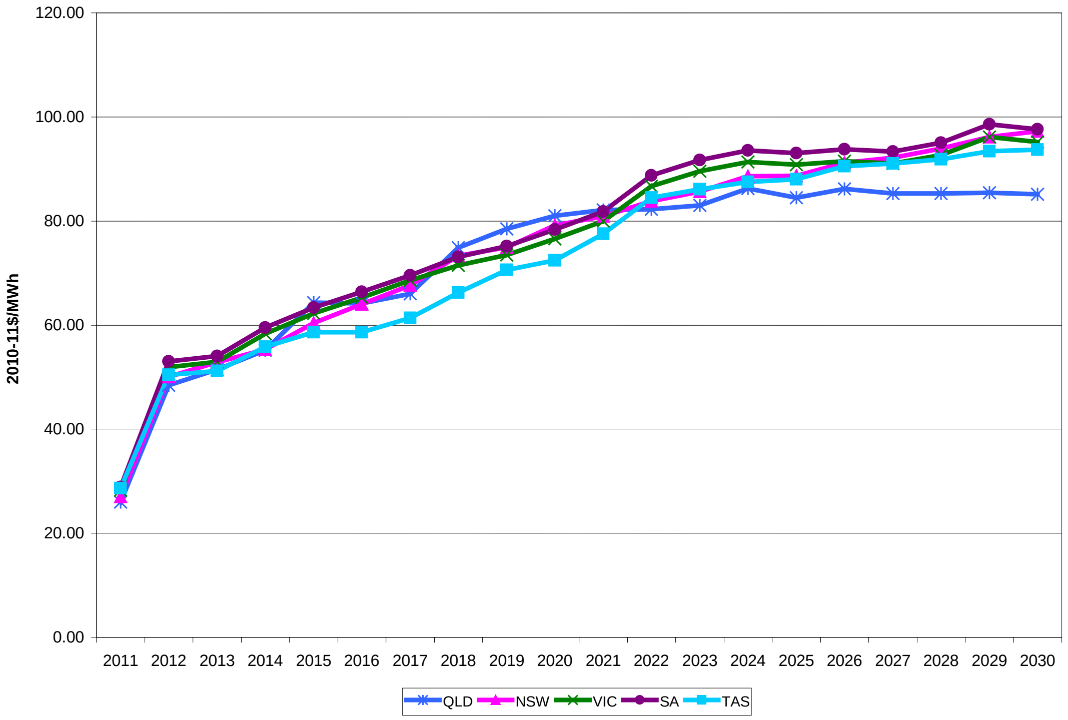
Towards the end of the LRET in 2020/21, there is a steeper increase in wholesale prices under the reference case and carbon emissions price scenario to 2030/31 as incentives under the LRET for renewable generation fall away and increased gas plant is installed. This occurs under the counterfactual scenario around 2018/19, as increased open and closed cycle gas is installed to meet forecast increasing levels of demand.

Figure 3.7 Forecast wholesale prices in the NEM - Reference case



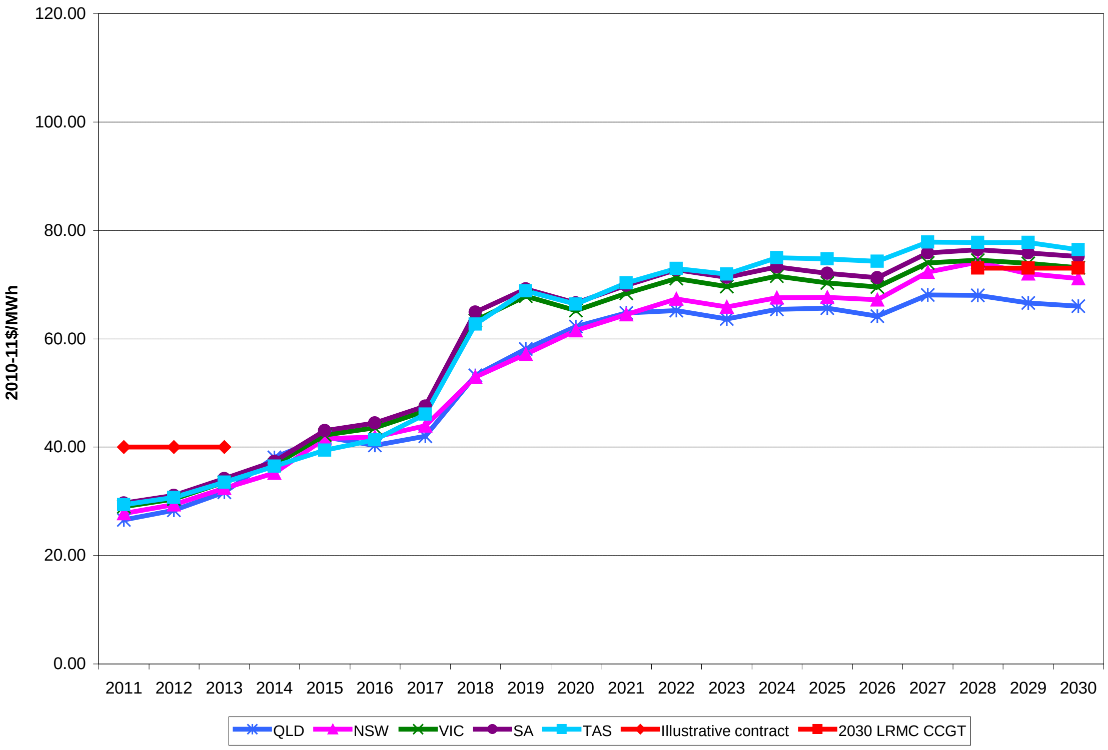
Note: Data represents financial years (e.g., 2011 is 2011/12)

Figure 3.8 Forecast wholesale prices in the NEM - Carbon emissions case



Note: Data represents financial years (e.g., 2011 is 2011/12)

Figure 3.9 Forecast wholesale prices in the NEM - Counterfactual case

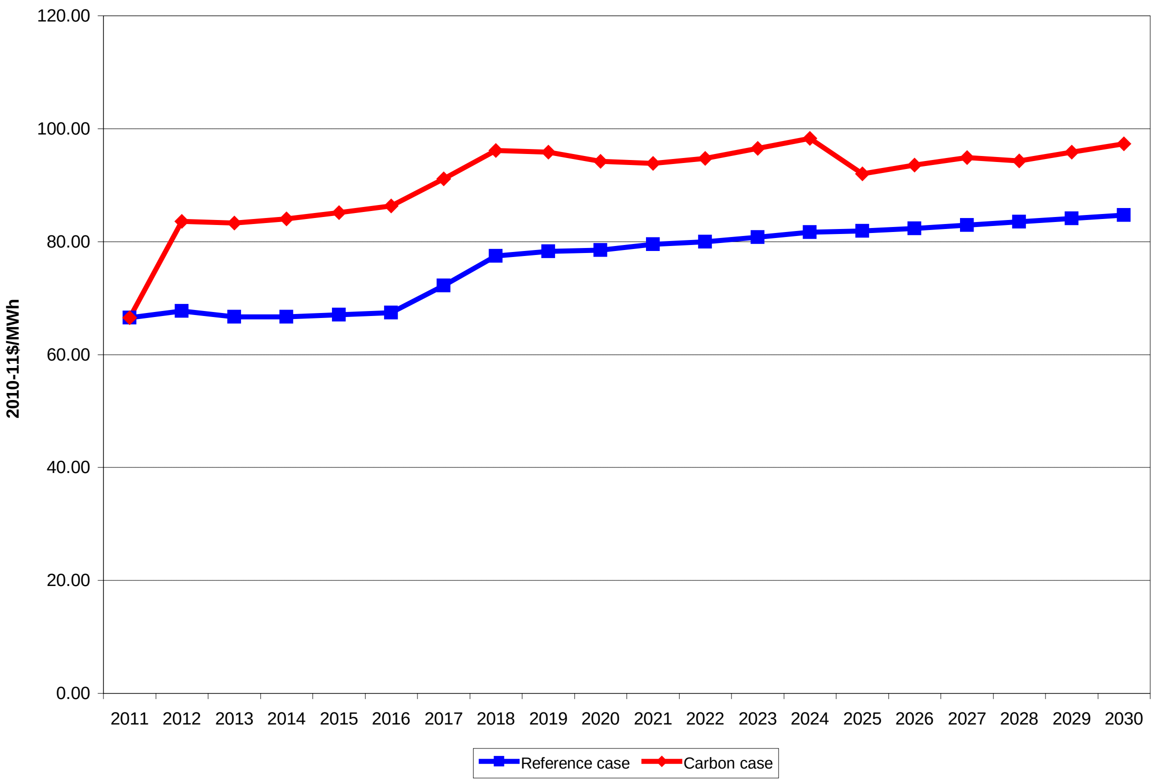


Note: Data represents financial years (e.g., 2011 is 2011/12)

In the SWIS in Western Australia, wholesale prices are the same under both the counterfactual and the reference case as current and committed levels of renewable generation as at late June 2011 are sufficient to meet Western Australia's pro rata share of the LRET. Prices under the reference case (and counterfactual) are forecast to increase from around $67/MWh in 2011/12 to $79/MWh by 2020 in 2010/11 dollars, which is around $30/MWh higher than in the NEM by 2020/21. Wholesale prices under the carbon emissions price scenario are around $94/MWh in the SWIS by 2020/21 in 2010/11 dollars. Wholesale prices in the SWIS are forecast to be comparatively flatter than forecast prices in the NEM under all scenarios.

These prices reflect Western Australia's reliance on gas and a moderate gas price of $7/GJ in 2009/10 dollars by 2020/21.[19] Wholesale prices in the SWIS increase from around 2017/18 because of the anticipated expiry of existing gas contracts and the replacement with higher priced fuel. However there remains considerable uncertainty about future gas prices. Higher gas prices than have been assumed would further increase wholesale prices.

Figure 3.10 Forecast wholesale prices in the SWIS - Reference/ counterfactual and carbon cases



Note: Data represents financial years (e.g., 2011 is 2011/12)

[19] Additional transport costs of around $1/GJ in 2009/11 dollars are also assumed to take into account high capacity factor pipeline use.

In the Darwin-Katherine Integrated System, the wholesale cost of generation is forecast to remain relatively flat in real terms between $70/MWh and $75/MWh over the outlook period to 2030/31. These prices have been based on the new entrant costs of open cycle gas plant operating at relatively high utilisation.

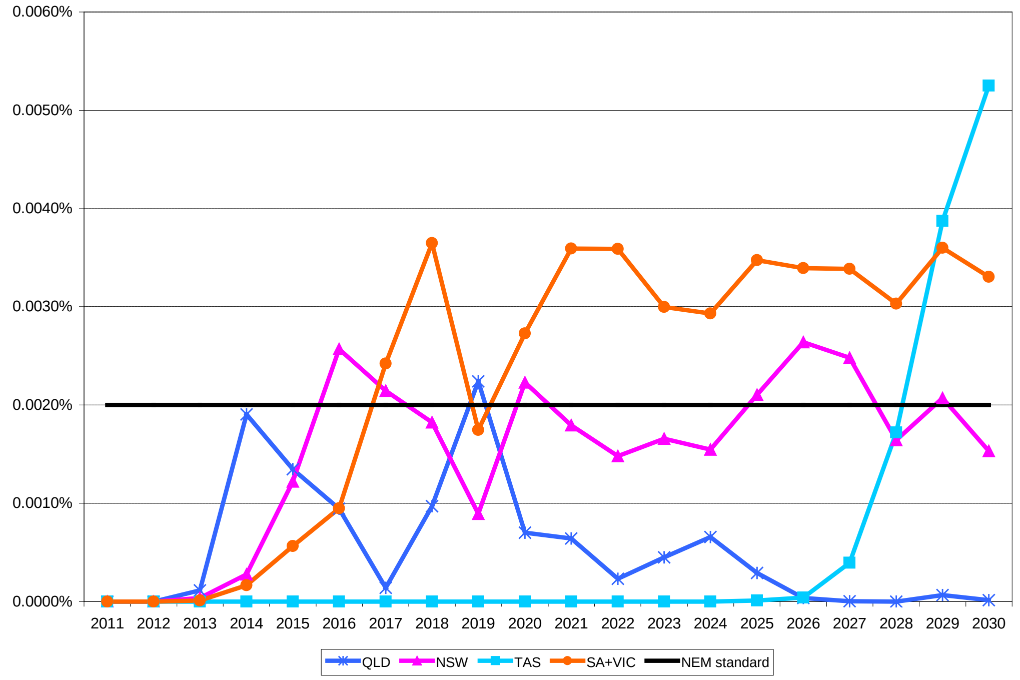
Impact on unserved energy

NERA/ Oakley Greenwood have also undertaken some analysis of the forecast level of unserved energy under the scenarios modelled. As this was not the primary focus of the Commission's assessment, these results should be treated with some caution. Our results highlight a potential issue that warrants further detailed analysis and consideration rather than a definitive assessment of the likely level of unserved energy at this time. It should also be noted that as the reliability of supply is expressed as a very small proportion of time when demand may not be met, there is the potential for a margin of error to arise in our modelling which may affect forecast outcomes.

The magnitude of the level of unserved energy is also sensitive to the policy settings for any price on carbon emissions that is introduced, contract market dynamics, and key assumptions such as future gas prices. Where gas prices are higher than the mid range gas prices that have been assumed, there is the potential that the profitability of peaking gas fired generators may be further reduced which would increase the forecast level of unserved energy.

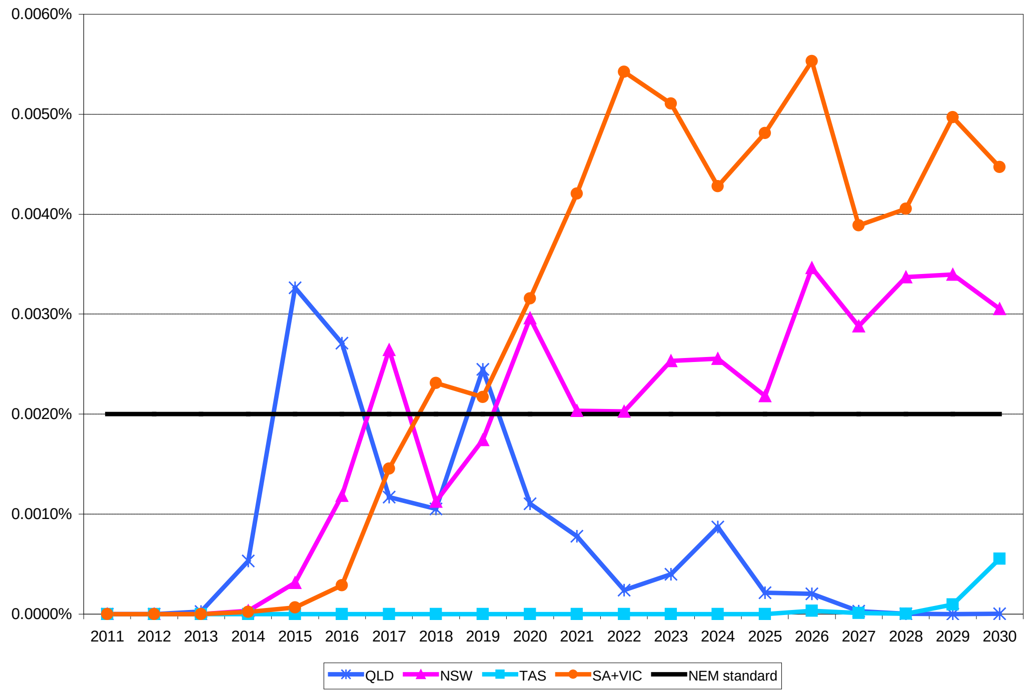
Under the reference case, depressed wholesale prices and limited running time for open cycle gas turbines, particularly due to the intermittency of wind generation, reduce the profitability of non-renewable generation options. This may lead to difficulties with meeting reliability standards in a number of years in some jurisdictions. This is also seen in the counterfactual and carbon emissions price scenarios. However, the level of forecast unserved energy is generally lowest in the counterfactual case as higher wholesale prices under the counterfactual increase the profitability of non-renewable generators.

Figure 3.11 Forecast unserved energy - Reference case



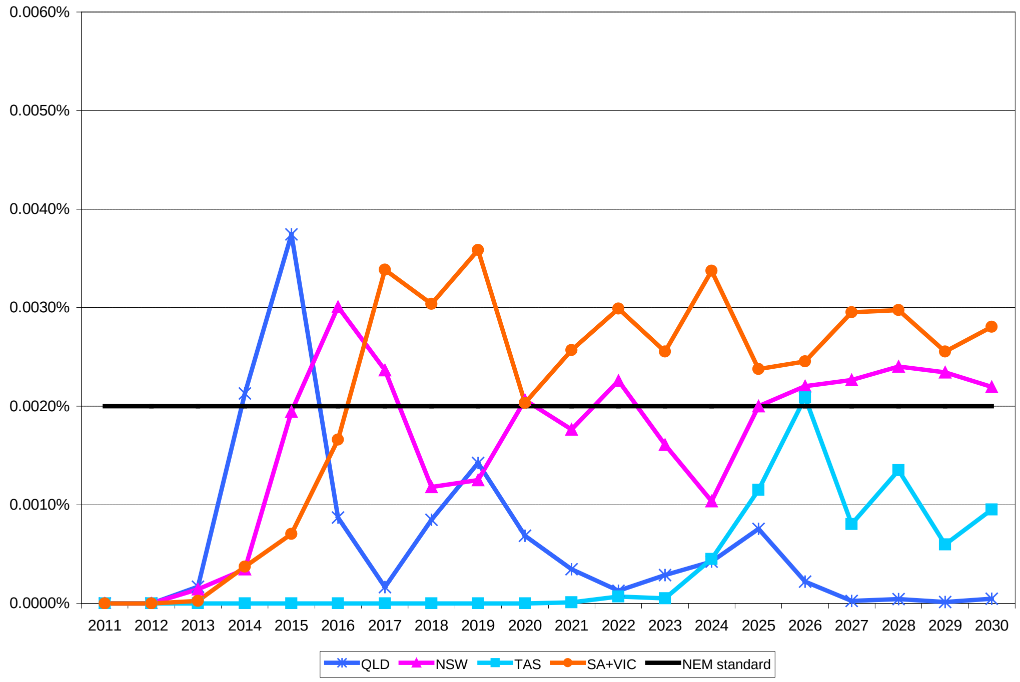
Note: Data represents financial years (e.g., 2011 is 2011/12)

Figure 3.12 Forecast unserved energy - Carbon case



Note: Data represents financial years (e.g., 2011 is 2011/12)

Figure 3.13 Forecast unserved energy - Counterfactual case



Note: Data represents financial years (e.g., 2011 is 2011/12)

In the carbon emissions price scenario there are still high levels of unserved energy forecast in some years as the carbon emissions price tends to increase base and intermediate load prices more than peak load prices. As unserved energy is primarily the result of the level of coverage for peak load, the increase in total capacity under the carbon emissions price only has a moderate effect on the level of forecast unserved energy compared to the reference case. As a result, the modelled carbon emissions price alone is not sufficient to provide for the profitability of peaking gas plant which could assist in reducing the level of unserved energy.

If South Australia and Victoria are treated as a single region for the purposes of maintaining reliability, the level of unserved energy is less severe. This reflects the linked reserve margin which is used by AEMO in practice. However, unserved energy in excess of the reliability standard still occurs from around 2015/16 onwards in the NEM under all scenarios.

As discussed above, because the contract market has not been specifically examined, the influence of a contract premium on bringing some generation investment forward has not been considered. In practice, generators tend not to contract all of their generation capacity with retailers, ensuring some is held back to manage contract requirements during outages. Further, it can be expected to some degree that retailers (especially those who are vertically integrated) will seek to avoid being exposed to very high prices brought about by insufficient generation capacity in the market and subsequent load shedding. Both factors will tend to mean contract prices will move ahead of actual underlying fundamentals to bring investment in generation capacity forward ahead of potential reliability concerns. However, these factors are complex to model and were not considered key to establishing the cost impacts of the LRET. The implication is however that this would make more generation profitable than might be indicated by the modelling.

We do not believe that other studies assessing the impact of the LRET have considered whether the unserved energy standard will be met. In Chapter 5 we discuss further the potential implications of the unserved energy standard not being met for security of supply and we outline further work that could be done to consider this issue prior to our Final Report.

In Western Australia there are no equivalent concerns for the level of unserved energy in the SWIS as current and committed levels of renewable generation in the SWIS as at late June 2011 are forecast to satisfy Western Australia's assumed allocated LRET requirement. As a result, renewable generation does not result in any additional depression in wholesale prices in the SWIS.

Forecast impact of the LRET on retail electricity prices

As discussed above, it is forecast that under policy settings as at late June 2011, wholesale electricity prices will be depressed as a result of additional renewable generation and are forecast to be approximately $10 to $15/MWh lower by 2020/21 than if the LRET was not in place. Lower wholesale electricity prices will reduce the wholesale purchasing cost of electricity for retailers. Whether these lower purchasing costs are passed through to consumers will depend on how the wholesale cost allowance in regulated retail electricity prices is set and the degree of retail competition there is in each jurisdiction. A summary of how the wholesale cost allowance for regulated retail electricity prices is set in each jurisdiction is outlined below in Table 3.1

Table 3.1 Methodologies used to set wholesale cost allowances

Jurisdiction	Wholesale cost allowance methodology	Impact of the LRET on wholesale cost allowance
Australian Capital Territory	Bases allowance on market based prices. Market prices are based on average d-cypha Trade forward prices for base load electricity over the past two years and are multiplied by the load shape and hedging costs. Hedging costs are based on the additional risk premium required to purchase caps to manage the risk of high price events.	The wholesale cost allowance would be lower under the LRET compared to previous years. As average market prices over a number of years are taken into account, the full effect of lower market prices would take time to filter through.
New South Wales	Bases allowance on the higher of LRMC or market prices. The LRMC of generation is estimated on the basis of building a new least-cost generation system to meet the regulated load. Market based prices are based on modelling simulated forward data and considers publicly available information, e.g. d-Cypha data.	LRMC would be used to set the allowance, as market based prices are forecast to be lower under the LRET. As a result, there would be a limited impact on the allowance.
Northern Territory	Regulated retail electricity prices are currently set below cost reflective levels. There is limited	Lower wholesale prices may reduce the cross

Jurisdiction	Wholesale cost allowance methodology	Impact of the LRET on wholesale cost allowance
	information on how wholesale cost allowances are determined.	subsidy paid by the Northern Territory Government to consumers if retail prices remain unchanged.
Queensland	Uses an equally weighted average of LRMC and market prices. LRMC of energy is estimated on the basis that the entire generation system is built new at the outset using the most efficient combination of new plant to meet the nominated load. The market price of energy is estimated based on a combination of contract and spot market energy prices that a prudent and efficient retailer could be expected to purchase over a two-year period in order to meet the NEM load.	Market prices are forecast to be lower under the LRET. However, as market prices only form half of the wholesale cost allowance, the wholesale cost allowance should only be slightly lower compared to previous years.
South Australia	Applies LRMC to its estimates of electricity supply costs. ESCOSA considers a market-based approach to be unreliable on the basis of insufficient liquidity in the contract market for wholesale energy in South Australia.	Limited impact as the LRMC of generation would remain unchanged under the LRET.
Tasmania	Bases estimates on the LRMC of electricity supply while being mindful of the need to ensure that the allowance is adequate for Aurora to recover its efficient costs through its retail tariffs for non-contestable customers.	Limited impact as the LRMC of generation would remain unchanged under the LRET.
Victoria	The regulation of the prices for electricity and gas standing offer contracts in Victoria ceased on 1 January 2009. Standing offer contract prices are now set by each retailer in Victoria.	Any reductions in the wholesale price should be passed through to consumers by retailers, where retail markets are competitive.
Western Australia	Bases estimates on the LRMC of electricity supply for contestable customers. For non-contestable customers, the allowance is based on a weighted average of the Verve Energy sustainable energy price and forecasts of the LRMC of wholesale electricity. Regulated retail electricity prices are currently set below cost reflective levels.	No impact as the LRET is forecast to have no impact on forecast wholesale prices in WA.

Generally, in those jurisdictions where regulated retail prices are set on the basis of market prices, the forecast lower wholesale prices should be passed through to consumers. However, in jurisdictions where the wholesale cost allowance for regulated retail prices is based on the long run marginal costs of generation, there is likely to be a limited impact on the wholesale cost allowance as long run marginal costs will remain relatively stable over the outlook period. As a result, in these jurisdictions consumers are unlikely to benefit from the lower wholesale prices that may result from the LRET.

In jurisdictions where there is a high level of retail competition, retailers may pass through lower wholesale purchasing costs to their customers on market contracts to retain market share. This is likely to occur in Victoria in relation to customers on both standing and market contracts, as retail electricity prices are no longer regulated in this jurisdiction.

For Western Australia, the LRET will have no effect on wholesale prices, as wholesale prices are forecast to remain the same under both policy settings as at late June 2011 and if the LRET was not in place. In the Northern Territory, as regulated retail electricity prices are currently set below cost reflective levels, depressed wholesale electricity prices may assist in reducing the level of subsidy which is paid by the jurisdictional government to electricity consumers.

Although the LRET may result in lower wholesale electricity prices than would have occurred if the LRET was not in place (except in Western Australia), the effect this will have on the total wholesale cost allowance and regulated retail electricity price will depend on movements in other components of the allowance and regulated price. Any reductions that may have occurred in regulated retail electricity prices as a result of lower wholesale prices are forecast to be offset by the compliance costs of the LRET and SRES. As a result, the net effect of the enhanced RET would be to increase forecast retail electricity prices for consumers. Further details on the costs of complying with the LRET and SRES are discussed below.

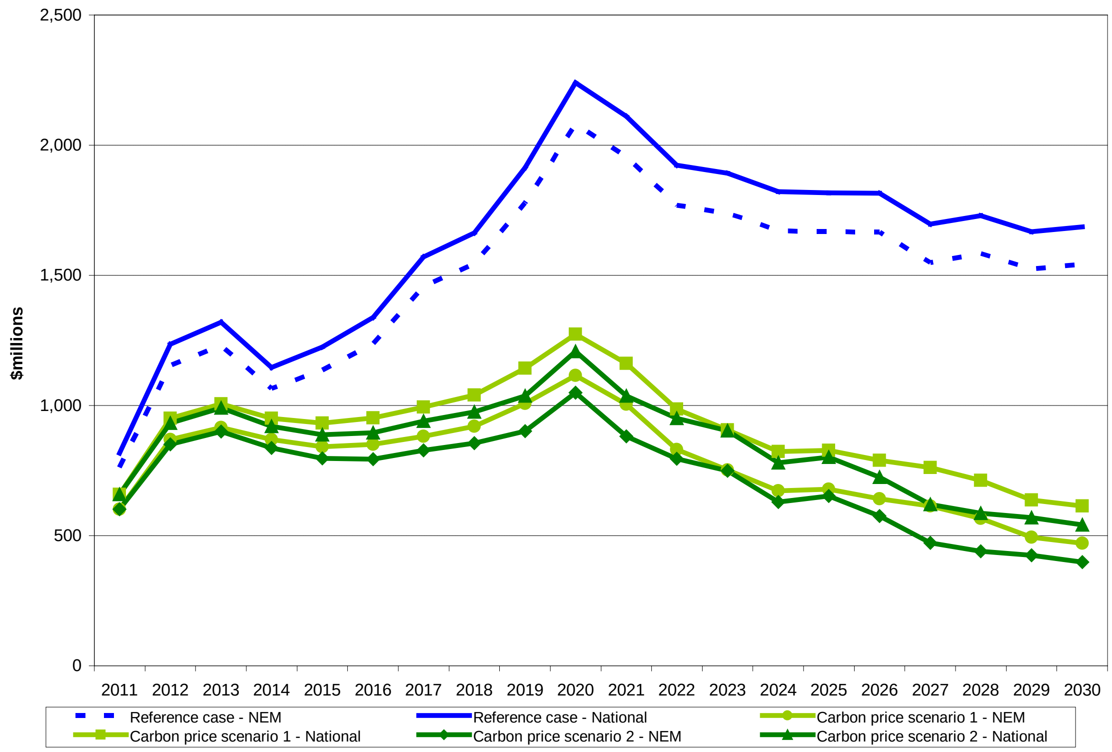
Forecast compliance costs of the LRET

As discussed above, the LRET is forecast to depress wholesale electricity prices which may lower the retail electricity price for some customers. However, consumers will also be required to pay for the compliance costs associated with the LRET which are borne by retailers. LRET compliance costs reflect the retailer's cost of purchasing LGCs to meet their liabilities under the LRET. As we have forecast that the LRET annual targets are unlikely to be met in any years of the outlook period, the shortfall between the forecast level of renewable generation and the LRET annual targets will need to be met by retailers through the payment of the penalty price.

The compliance costs associated with the LRET under policy settings as at late June 2011 are forecast to increase from around $812 million in 2011/12 to around $2.2 billion in 2020/21 in 2010/11 dollars. This increase in the cost of the LRET over the outlook period reflects the annual increases in the LRET out to 2020. From 2020/21 onwards compliance costs are forecast to fall to around $1.7 billion in 2030/31 as the LRET is maintained and does not increase in size.

Compliance costs are lower under a carbon emissions price despite higher absolute levels of renewable investment. This reflects that a carbon emissions price lifts wholesale prices, and therefore reduces the level of support required from LGC prices for profitable renewable generation. As under the counterfactual there would be no LRET, the compliance costs of the LRET would be zero.

Figure 3.14 Forecast LRET compliance costs



Note: Data represents financial years (e.g., 2011 is 2011/12)

The majority of compliance costs are incurred by NEM participants, which account for around 92% of compliance costs under the reference case and between 77% and 91% in the carbon emissions price case.

As discussed above, as we have not explicitly modelled the LGC market, there is the potential particularly in the early years of the outlook period that LGC prices will be lower than we have assumed. If LGC prices continue to remain at levels, in the short term this would result in lower levels than forecast of renewable generation as profitability for renewable generators would be reduced. Lower LRET compliance costs would also eventuate for retailers and consumers due to lower LGC prices. However, in the longer term, LGC prices should rise as the current overhang of certificates is surrendered.

3.1.2 Impact of the SRES on retail electricity prices

Similarly to the LRET, wholesale purchasers of electricity also have a legal liability to purchase certificates under the SRES each year. The amount of certificates which need to be purchased each year is determined by the ORER, which sets the amount on the basis of the level of take up under the SRES in the previous year and the expected take up in the current year.

The future take-up and costs of the SRES are difficult to forecast as take-up is highly influenced by a range of factors that are particularly difficult to forecast, including the future path of retail electricity prices, the future cost of solar PV technology and the future policy settings for the SRES itself and jurisdictional FiTs.

Jurisdictional FiTs in particular have a significant influence on the future costs of the SRES, as they affect the number of Small Scale Technology Certificates (STCs) that are created. Increased numbers of STCs result in retailers being required to purchase a larger percentage of STCs under the Small Scale Technology Percentage set by ORER, which results in higher SRES costs for all consumers. As a result, the design of a FiT in one jurisdiction has implications for the costs all consumers will pay under the SRES. The installation of small generating units comprises the majority of all STCs generated under the SRES and is particularly sensitive to changes in these factors.

Although our assessment of the future take up and costs of small generating units and solar hot water has been based on a payback approach and a stock replacement approach, a range of other non-financial factors can affect the decision to install by households and businesses. This may include factors such as rising disposable incomes, increased environmental awareness, and increased marketing of solar PV and hot water systems, amongst other factors. Some initial analysis of the demographic characteristics of energy consumers in postcodes which have had a high penetration of installations under the SRES is outlined in Chapter 6. This analysis also outlines the characteristics of consumers in postcodes which have been less likely to install small scale renewable technologies. Further analysis of these distributional impacts of the SRES may assist in understanding the types of non-financial factors which may influence take up. It may also assist in future policy development and in the targeting of small scale renewable energy schemes.

Forecast uptake under the SRES

Modeling on the impact of the SRES takes into account recent changes to the Victorian, Australian Capital Territory (ACT), South Australian and Western Australian feed in tariff schemes. These changes include the Victorian and South Australian new transitional feed in tariffs and the closing of the ACT's medium-scale feed in tariff and the Western Australian feed in tariff after caps for these schemes were reached.

We are forecasting that by 2020 a total of 6,390 GWh of electricity would be displaced under the SRES when the impact of both the SRES and jurisdictional FiTs are taken into account. This is comprised of 3,170 GWh from solar PV installations and 3,220 GWh from solar hot water installations, and is outlined in Figure 3.15 below. This is 60% higher than the aspiration of 4,000 GWh by 2020 for the SRES when the enhanced RET policy was put in place, and implies a penetration of solar PV to 27% of eligible houses in Australia by 2020.[20] When the effect of jurisdictional FiTs is removed, it is forecast that 4,431 GWh of electricity would be displaced by 2020 as a result of the SRES, which is 11% higher than the SRES' aspiration of 4,000 GWh.[21] We are forecasting that a total of around 110 million STCs would be created by 2019/20.

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20 We have calculated this figure as a percentage of detached and semi-detached houses. While we acknowledge that some terraced houses and flats may be able to install solar PV, it is likely to be a small minority.

21 However, we note that it is difficult in practice to isolate the net effect of the SRES, as consumers install small scale renewable technologies as a result of the cumulative effect of incentives provided under both the SRES and jurisdictional FiTs.

A number of recent policy changes have been made to reduce the level of demand under the SRES and jurisdictional FiTs as it has been generally far higher than expected. This highlights the difficulty and complexity of forecasting uptake and costs under these schemes. These policy changes seek to reduce the incentives provided for solar PV, while rebates for solar hot water under policy settings as at late June 2011 will remain unchanged over the outlook period. As a result the proportion of STCs which are created by solar PV is forecast to fall from 93% of all STCs in 2010/11 to 65% in 2019/20.

Figure 3.15 Forecast electricity displaced by small scale technologies

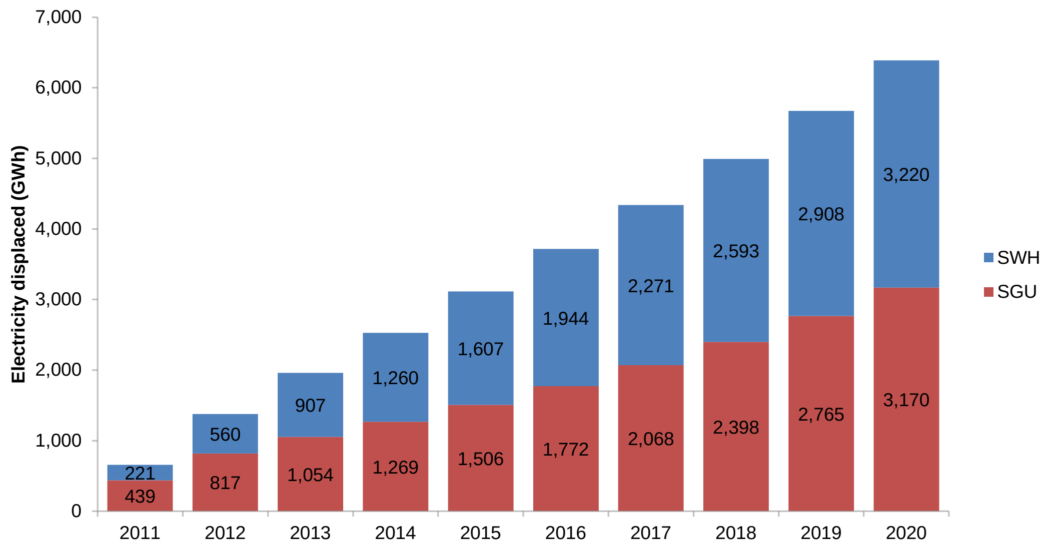
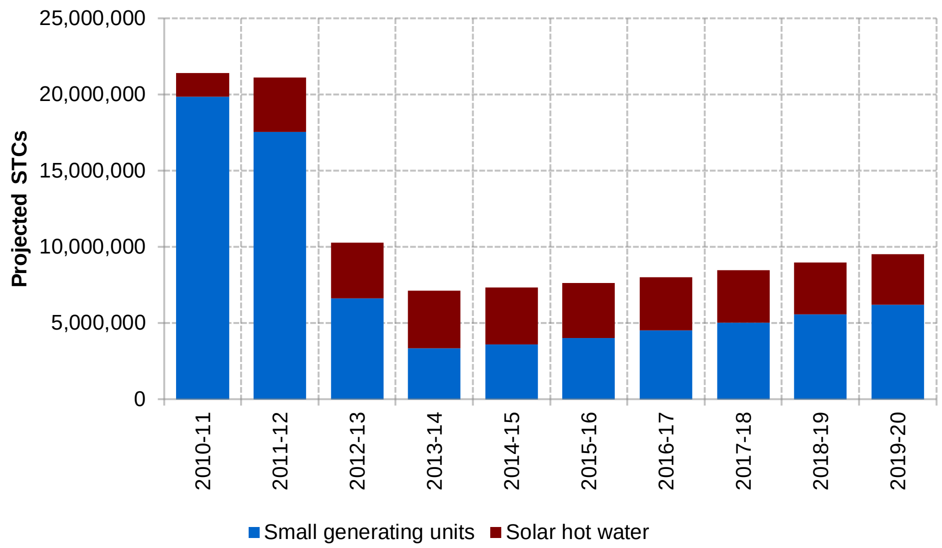


Figure 3.16 Forecast number of STCs by technology type



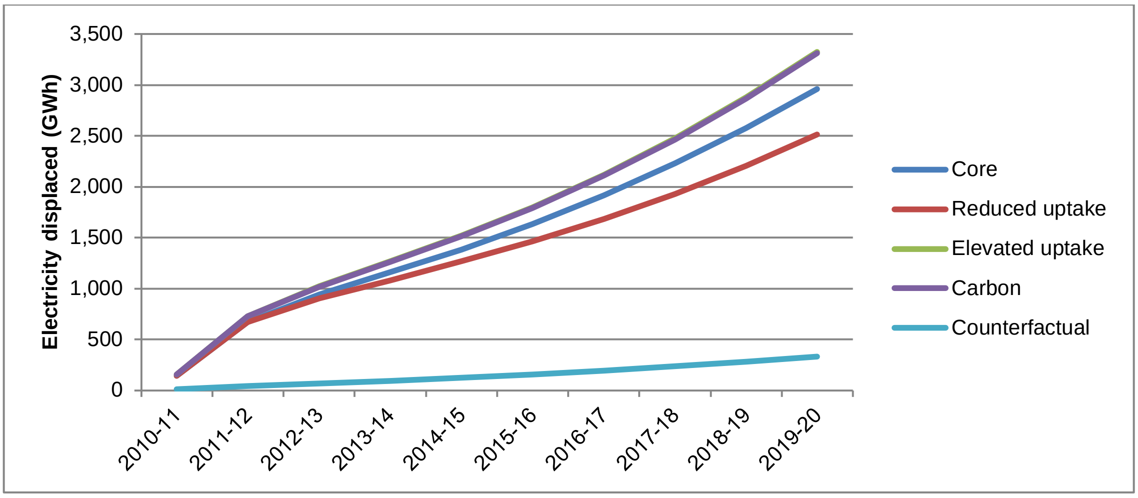
Installations of solar hot water are forecast to be driven in part by jurisdictional government regulations (e.g. NSW, Victoria, Queensland, South Australia, Western Australia) which have effectively banned electric hot water heaters in new buildings and for the replacement of existing water heaters (Queensland, South Australia).

If a carbon emissions price is introduced in 2012, a further 384 GWh of renewable electricity is forecast to be generated by 2020 compared to the reference case, with 6774 GWh generated by 2020. This is around 69% above the SRES' implicit target. Forecast results under a carbon emissions price scenario are very similar to forecast results under an elevated uptake scenario, where it is assumed that caps are relaxed and tariff rates are increased under jurisdictional FiTs. Results under the reduced uptake scenario, where the Solar Credits Multiplier reduces at a faster rate and STC prices and jurisdictional FiT caps and tariff rates are lower, the forecast level of renewable generation is 11% lower by 2020 than the reference case. Under the reduced uptake scenario, forecast renewable generation would still be 43% higher than the SRES' implicit target of 4,000 GWh at 5,733 GWh.[22]

The Solar Credits Multiplier is a important variable in influencing uptake under the SRES as it affects the rate of STC creation for any given level of small generating unit installation by adjusting the number of STCs that the installation can create and it also affects the financial attractiveness of small generating units and the rate of installation.

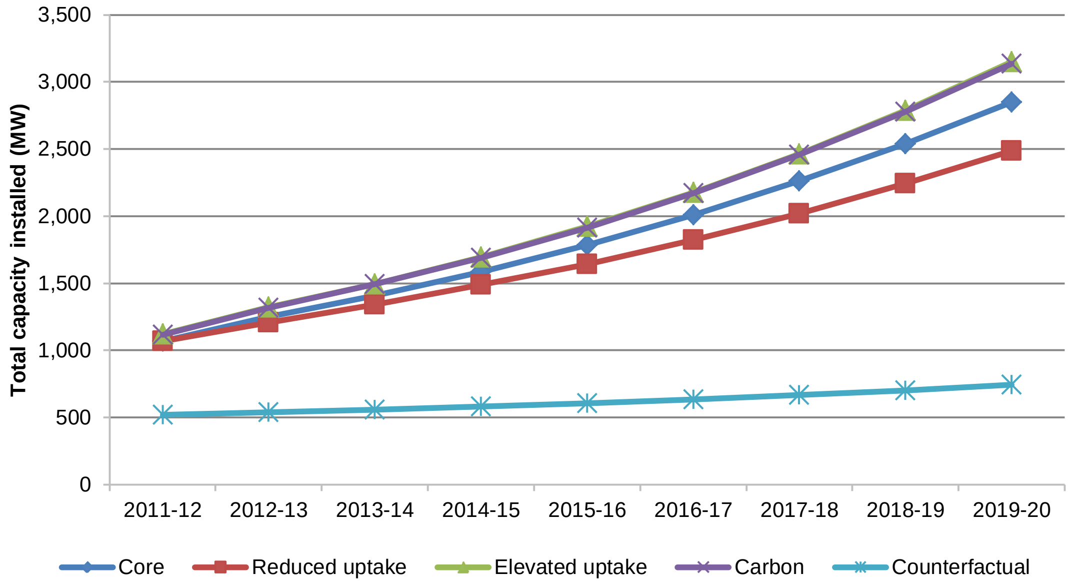
Under the counterfactual scenario (i.e. no RET or Solar Credits Multiplier), there is significantly less uptake compared to the other modelled scenarios. Uptake under the counterfactual scenario is predominantly driven by future retail electricity price movements, jurisdictional FiTs and other rebates.

Figure 3.17 Forecast renewable generation by solar PVs



22 Forecast renewable generation under the carbon emissions price scenario, elevated uptake, and the reduced uptake scenario are based on reference case results for solar hot water.

Figure 3.18 Cumulative capacity of forecast solar PVs installed



Over the outlook period, the pattern of installations for solar PV are forecast to fall steadily from a peak in 2011 and 2012 until around 2014 as the Solar Credits Multiplier reduces and most jurisdictional FiT schemes have reached their cap, worsening the financial payback that can be achieved by energy consumers. From around 2015 onwards installations begin to climb, albeit slowly, with reductions in system costs and expected increases in retail electricity prices. PV system costs are expected to decline strongly in real terms out to 2020, with PV system costs in 2020 forecast to be less than half of system costs in 2009 in real terms.

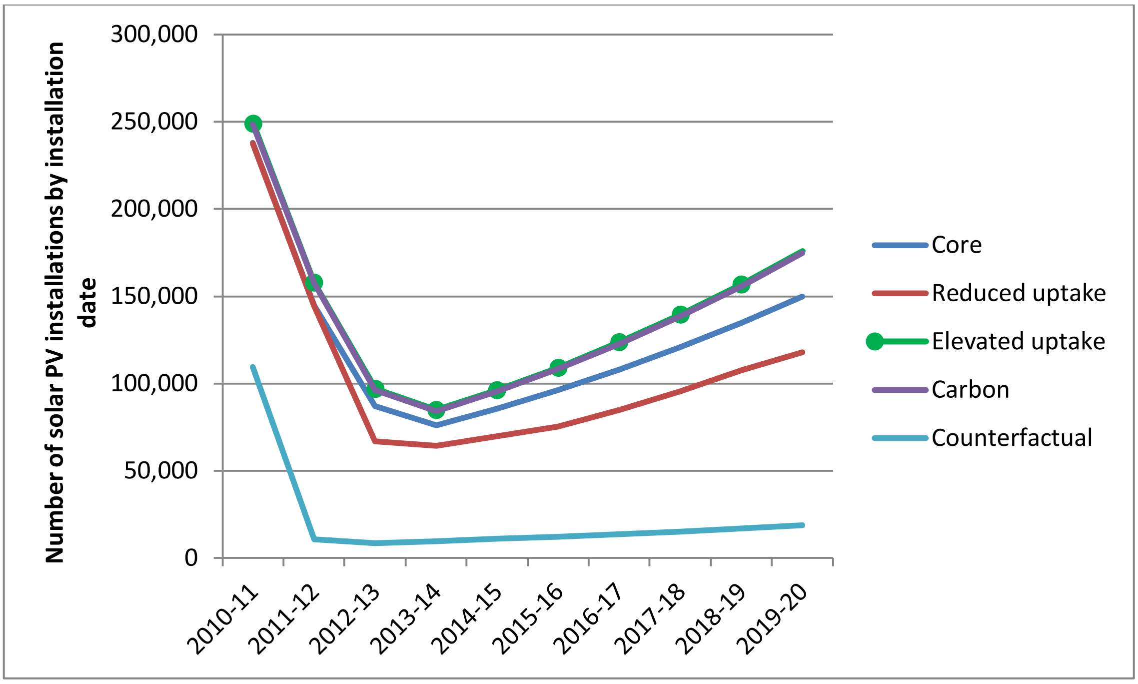
By 2020, payback periods for solar PV are not significantly different from current subsidised levels. However, by 2020 installations still remain below the levels that were seen at the beginning of the outlook period. This indicates that the financial benefits that consumers receive as a result of the Solar Credits Multiplier and jurisdictional FiTs are not expected to outweigh forecast reductions in system costs and retail price increases.

Under the reference case a total of 1.4 million solar PV installations are forecast by 2020, which is an increase of around 1 million additional installations from the level as at late June 2011 of around 400,000. NSW is expected to comprise 31%, Queensland 27%, Victoria 17%, Western Australia 14% and South Australia 9% of total forecast installations. Other jurisdictions are forecast to comprise a relatively small proportion of aggregate capacity at 66MW.

For all scenarios, except for the counterfactual, the pattern of installations follows a similar path with some differences in outcomes between the scenarios. Installations under the reduced uptake scenario fall at a faster rate in the first half of the outlook period compared to the reference and carbon emissions price scenarios, due to faster reductions in the Solar Credits Multiplier.

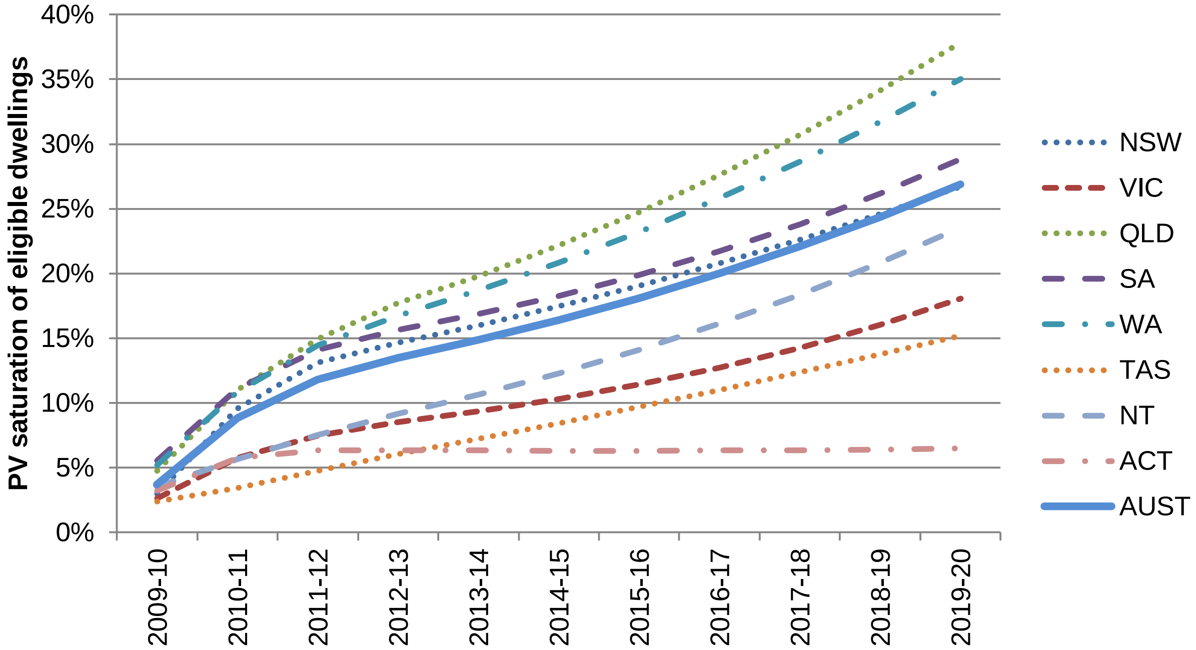
Growth in installations under the reference and carbon emissions price scenarios increase at a faster rate compared to the reduced uptake scenario towards the end of the outlook period. This is the result of reductions in jurisdictional FITs under the reduced uptake scenario compared to the reference and carbon emissions price scenarios, and higher retail electricity prices under the carbon emissions price scenario. Differences in the number of installations between scenarios reflect a combination of differences in the timing of the Solar Credits Multiplier reductions, STC clearing house prices, jurisdictional FiT scheme rates and caps, and expected retail electricity prices.

Figure 3.19 Forecast number of installations of solar PV by scenario



By 2020, the saturation of PV systems in owner-occupied dwellings is expected to grow from around 6% at the end of 2010 to 27% by t2019/20. However, there are significant differences between jurisdictions. Differences between jurisdictions reflect differing levels of solar irradiation which affect the total output of each installation and the number of STCs which can be created, jurisdictional FiT scheme rates and caps, expected retail electricity prices, and labour installation costs for PV systems. Queensland and Western Australia are forecast to have the highest levels of penetration by 2019/20, with over 35% of eligible houses having solar PV installed. The ACT has the lowest penetration level at less than 7% with limited installations occurring once its FiT reaches its cap due largely to the relatively low retail electricity prices in that jurisdiction.

Figure 3.20 Forecast level of solar PV saturation



Forecast cost of the SRES

The forecast pattern of installations under the SRES is reflected and amplified in the forecast costs of the SRES. This occurs as the direct cost of the SRES is paid by all consumers in the year in which the installation is registered, as all STCs that a system is deemed to produce over its lifetime are created in the registration year. As the pattern of installations changes significantly over the outlook period and may also be subject to further changes if there are changes in factors such as policy settings and expected retail electricity prices, this has the potential to create a volatile price impact on consumers.

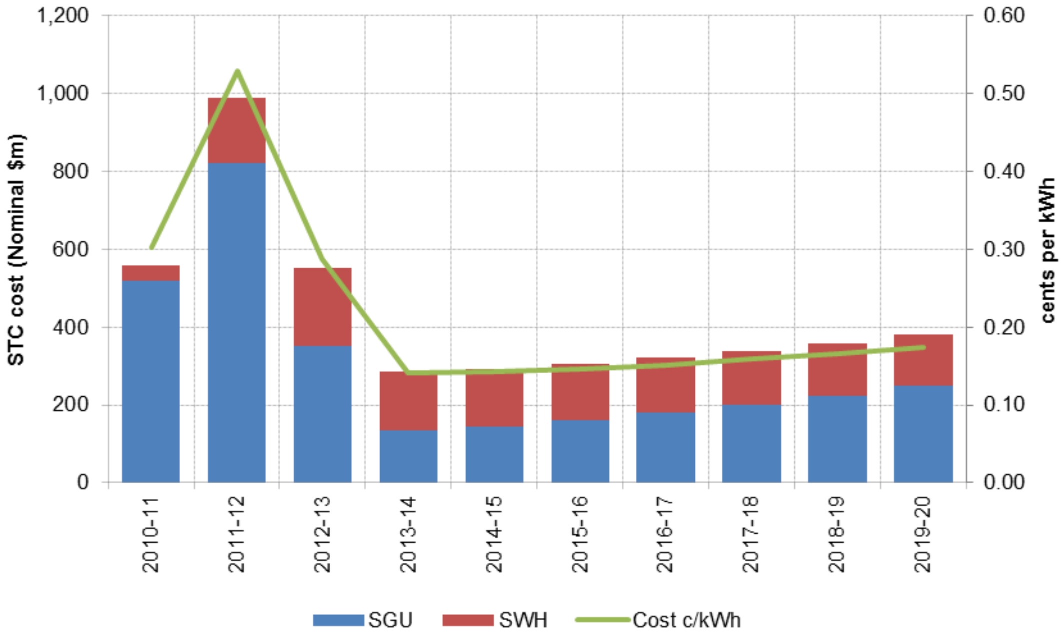
STC are available for purchase or sale through a clearing house managed by ORER at a legislated fixed nominal price of $40 per a STC.[23] STCs can also be traded bilaterally and in recent months have traded significantly below the nominal $40 price due to an excess supply of certificates and cash flow constraints for a number of installers. As it is unclear what proportion of certificates are trading below the $40 fixed price or the period of time that certificate prices will be traded at a discount, the nominal clearing house price of $40 per a STC has been used to estimate future STC costs.

In nominal terms, the cost of the SRES is expected to fall from around $989 million in 2011/12 to around $381 million in 2019/20 under policy settings as at late June 2011. The significant reduction in annual costs between 2010/11 and 2019/20 reflects the expected fall in installations over the life of the SRES as the incentives under the Solar Credits Multiplier and jurisdictional FiTs reduce. In nominal terms, the cost of the

23 See section 30LA(1) of the *Renewable Energy (Electricity) Act 2001*. Under this legislation the relevant Minister may also adjust the clearing house price to less than $40 at any time by legislative instrument.

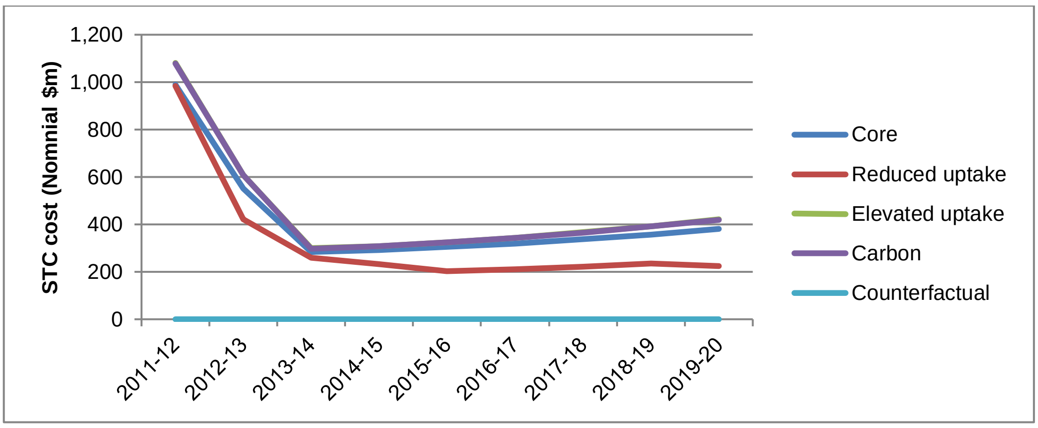
SRES is forecast to be $37 in 2011/12 per a household and would fall to $12 per a household in 2019/20.[24]

Figure 3.21 Forecast STC costs under the reference case



The cumulative forecast cost of the SRES between 1 January 2011 and 30 June 2020 if policy settings as at late June 2011 are maintained is $4.4 billion in nominal terms. Under the reduced uptake scenario, cumulative costs are expected to be significantly lower at $3.6 billion which reflects lower expected uptake. Cumulative costs under the carbon emissions price scenario are $4.7 billion. This is similar to forecast costs under the elevated uptake scenario and are only slightly higher than forecast costs under the reference scenario.

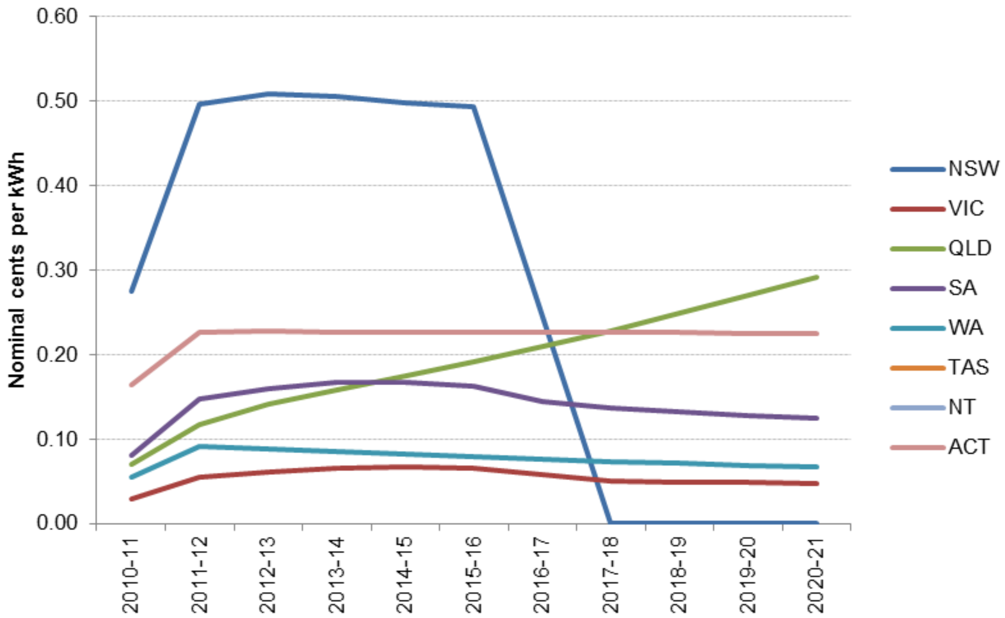
Figure 3.22 Forecast STC costs by scenario



24 Estimated household costs are based on an average annual consumption of 7000 kWh.

In addition to the costs of the SRES, all energy consumers will also pay for the costs of jurisdictional FiTs for the life of the systems that have been installed as a result of incentives provided under both the SRES and jurisdictional FiT schemes. These costs will vary significantly by jurisdiction, depending on the rate of installation, whether the scheme is a net or gross scheme, and the caps and FiT rates that apply, amongst other factors. An indicative estimate of the forecast cost of FiTs in each jurisdiction under the reference scenario has been made, using the forecast level of uptake and policy settings as at late June 2011 of each relevant FiT.

Figure 3.23 Indicative forecast of jurisdictional FiT costs under policy settings as at late June 2011



Implicit subsidies are also provided to solar PV installations as installations reduce the base of energy use over which network tariffs are recovered, which transfers the largely fixed costs of maintaining the network onto energy users that do not have PV systems. The compliance costs of schemes such as the SRES and jurisdictional FiTs are also transferred to other energy users.

3.1.3 Impact of the LRET on transmission and security of supply costs

This section presents the results of potential impacts of the LRET on ancillary services and transmission costs. A detailed explanation of what comprises ancillary services and how security of supply is currently managed in the NEM and SWIS can be found in Chapter 5.

Where it is assumed that the LRET is achieved without any retailers paying the penalty price, between 8000 MW to 9000 MW of additional renewable capacity is required to enter the market. The majority of this capacity would be wind. As a consequence of its variability, entry of such a large volume of wind generation is expected to increase the costs of maintaining a secure network in the following ways:

- Increase the requirement for Frequency Control Ancillary Services (FCAS) (regulation services in particular) or the equivalent in the SWIS (load following ancillary services or LFAS) which are required to manage the minute by minute variations in supply and demand on the network;
- Affect the requirement for some Network Support and Control Ancillary Services (NSCAS) on the network, in particular the need for voltage support and reactive power capability, depending on the type and location of wind farms installed; and
- Potentially increase the requirement for investment in transmission capacity, due to the different locations that wind generation capacity might locate, relative to historical generation patterns.

As these costs are primarily associated with renewable intermittent resources, we were keen to investigate their potential materiality in achieving the LRET.

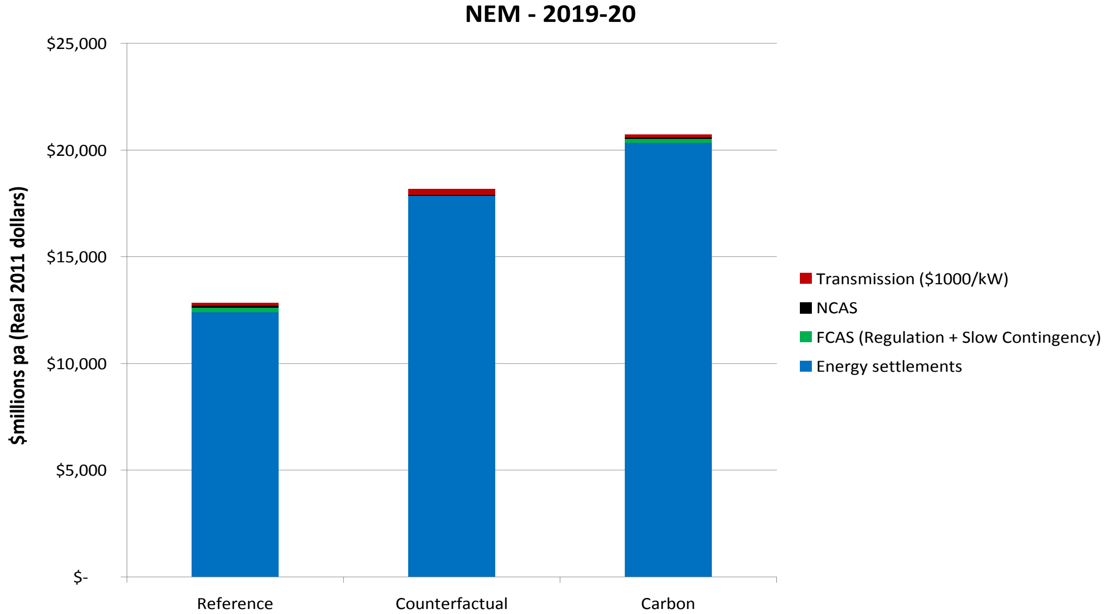
We modelled the ancillary services and transmission requirements for the enforced LRET case in the reference scenario (where the penalty price was effectively removed), and compared this with the counter factual (where there is no LRET). This assumption can be regarded as testing an upper limit of potential costs.

There is considerable uncertainty around forecasting actual unit transmission costs given the range of capacities and technology types that might be used for transmission investment. For this reason the modelling used a lower bound of $500/kW and higher bound of $1000/kW to capture the likely range in costs.

While the modelling performed by ROAM for this study was more comprehensive than other studies that have investigated this issue, it should be noted that only intra-regional and inter-regional augmentations between the 16 NTNDP zones were assessed, and no augmentations were assessed within the zones. Nevertheless, this methodology should capture the major trends in transmission investment costs between the scenarios. The transmission unit values used are consistent with those used by AEMO in the NTNDP in their “uncertain world” scenario.

A summary of key results of the modelling is shown in Figure 3.24 below. Only results for the NEM are illustrated here, as ancillary services and transmission requirements in the SWIS out to 2020 did not differ on the basis of whether there was an LRET in place (due to the same forecast generation profile under each scenario). Thus the LRET does not impact the quantum of these costs for the SWIS. These findings are discussed in detail in ROAM's modelling report.

Figure 3.24 Summary of ROAM's modelling of FCAS and transmission for the NEM in 2019-20



It is important to note that the future costs of ancillary services and transmission are difficult to forecast as they are based on future energy flows, which depend on generation dispatch and location decisions. The conclusions should therefore be interpreted with care.

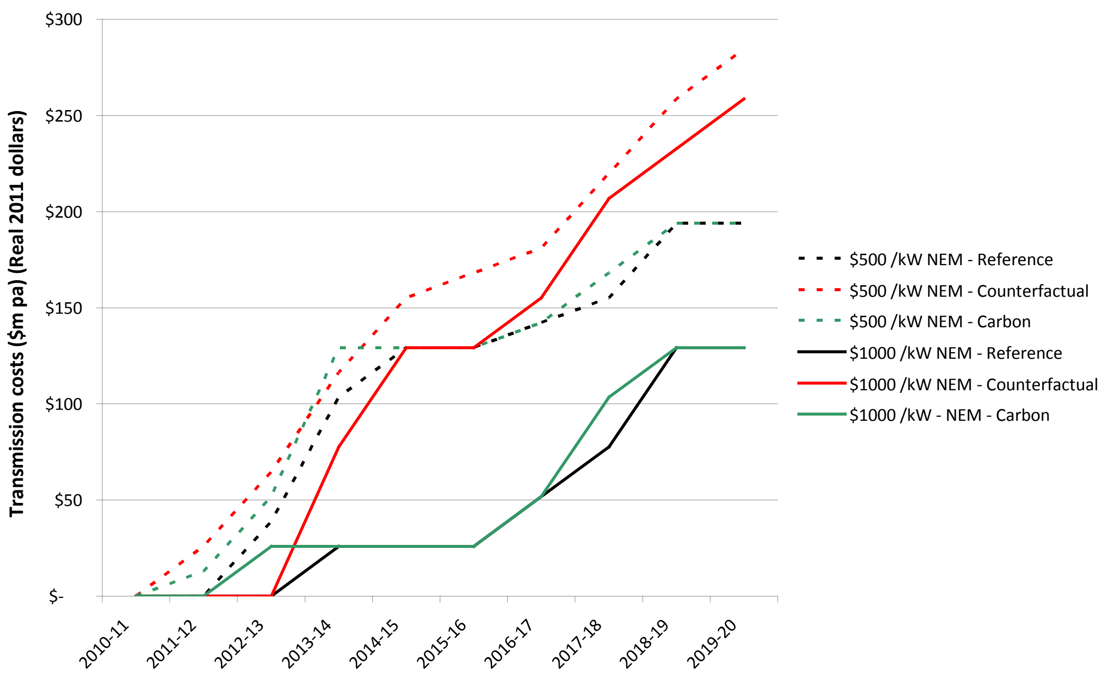
The graph shows that in absolute terms ancillary services are forecast to make up a only a very small component of overall energy costs. It can be concluded therefore that any net impact of these costs on retail electricity prices are also likely to be small. However, as we discuss further in Chapter 5, the relative increase in the requirement for regulation services from current levels as a consequence of the LRET is significant for both the NEM and SWIS and would fall disproportionately, under a causer pays methodology, on wind generators.

Figure 3.24 illustrates that transmission investment costs do not differ significantly between scenarios modelled (the $1000/kW case is shown). This suggests that it is forecast demand growth rather than the LRET that is the predominant driver of transmission investment requirements.

A break down of investment trends by year over the period modelled, in Figure 3.25 below, reveals a somewhat unexpected result. Transmission investment costs are generally forecast to be somewhat greater under the counterfactual scenario relative to the enforced LRET and carbon scenarios. That is, transmission requirements are less with the LRET in place.

The result can be explained, in part, by the increasing take up of biomass in the enforced LRET and carbon scenarios, which can meet load growth with limited additional network augmentation. It also assumes a relatively distributed pattern of wind generation locating relatively close to the existing transmission network. Further, a much higher penetration of baseload gas plant is forecast under the counterfactual scenario, which is expected also to drive significant augmentation requirements. This is due to the larger size of baseload gas relative to wind generators and the need for such capacity to increasingly utilise more remote gas fields over time. This is consistent with modelling performed by AEMO for the NTNDP in its "uncertain world" scenario, using a zero carbon price sensitivity (see Appendix C for further discussion on the approach by AEMO).

Figure 3.25 Transmission investment impacts over the outlook period



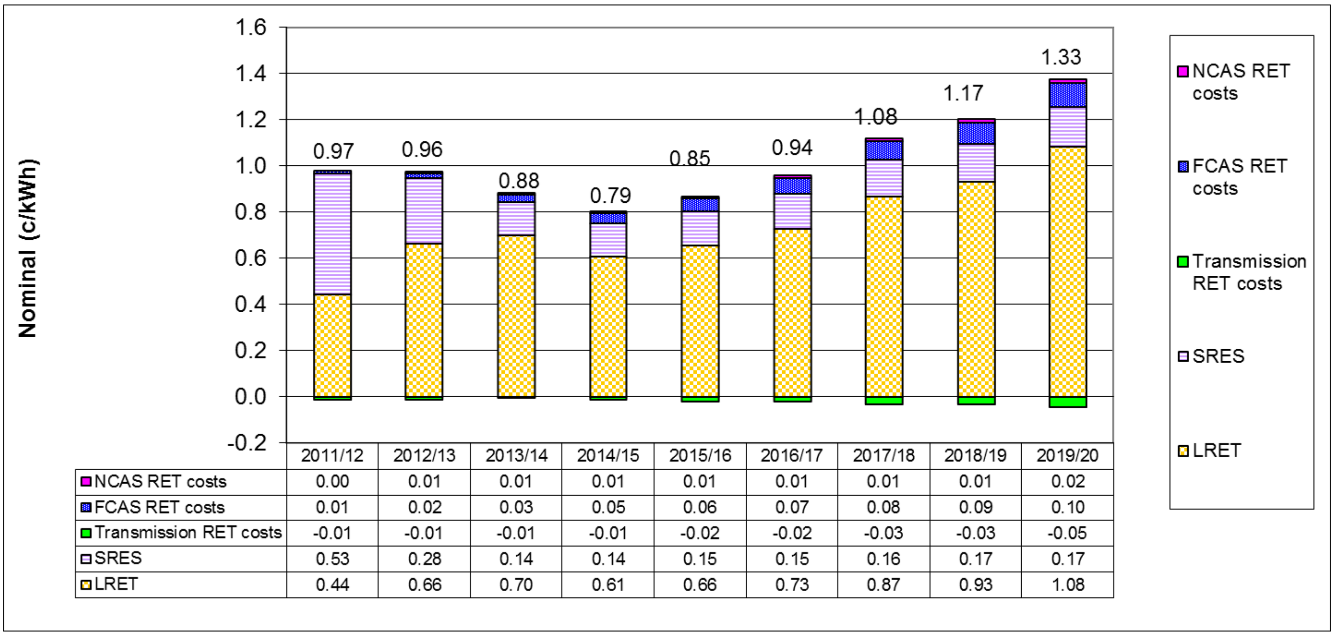
3.1.4 Total costs of the enhanced RET

The total compliance cost of the enhanced RET is expected to increase from $1.78 billion in 2011/12 to $2.20 billion in 2019/20 in 2010/11 dollars, based on the continuation of policy settings as at late June 2011.

Over the outlook period, the contribution of the various components of the enhanced RET are expected to change. In 2011/12, the SRES will contribute the majority of the total costs of the enhanced RET at 54%, but its contribution will fall to 13% by 2019/20. In contrast, the LRET is forecast to comprise an increasing proportion of total enhanced RET costs and is expected to comprise 46% costs in 2011/12 and 81% by 2019/20. These changes in the composition of the total costs of the enhanced RET reflect the increase in annual targets for the LRET towards 2020 and the effect of the reducing Solar Credits Multiplier and the end of jurisdictional FiT schemes on take up under the SRES.

Costs relating to maintaining security of supply are forecast to comprise only a small component of total costs relating to the enhanced RET over the outlook period and will contribute around 1-9% respectively over the outlook period. Under the enhanced RET transmission costs are forecast to be lower compared to if the enhanced RET was not in place as renewable generation is modelled to locate close to the existing transmission network. In contrast, where the enhanced RET was not in place, it is modelled that large volumes of baseload gas generation would be installed, which would locate further away from the existing transmission network (and require additional augmentations to the network) as more isolated gas fields are exploited over time.

Figure 3.27 Forecast RET costs in the NEM 2011/12 to 2019/20[25]



	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
NCAS RET costs	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02
FCAS RET costs	0.01	0.02	0.03	0.05	0.06	0.07	0.08	0.09	0.10
Transmission RET costs	-0.01	-0.01	-0.01	-0.01	-0.02	-0.02	-0.03	-0.03	-0.05
SRES	0.53	0.28	0.14	0.14	0.15	0.15	0.16	0.17	0.17
LRET	0.44	0.66	0.70	0.61	0.66	0.73	0.87	0.93	1.08

3.1.5 Summary

Our analysis of the impact of the enhanced RET on wholesale prices forecasts that:

- There is forecast to be a shortfall of about 35% compared to the LRET target of 41,000 GWh of large scale renewable generation by 2020/21, if policy settings as at late June 2011 are maintained.
- The LRET is forecast to depress wholesale prices, with wholesale prices not returning to the LRMC of baseload gas plant until 2025/26 to 2030/31.
- The combination of depressed wholesale prices and more intermittent requirements for open cycle gas plant means that there may be insufficient revenues for enough profitable new gas plant to enter to maintain the reliability standard in a number of years in some jurisdictions.
- There is a risk that consumers may not receive the benefit of lower wholesale prices, as the LRET creates a divide between wholesale prices and the retail prices paid by consumers. In addition, the compliance costs for customers of the LRET will be high because LGCs will trade at or close to the penalty price for a material proportion of the scheme's life due to the forecast shortfall in the LRET.
- It is forecast that there will be 60% more small scale renewable generation as a result of the SRES and jurisdictional FiTs by 2020 compared to the SRES' implicit target of 4,000 GWh, if policy settings as at late June 2011 are maintained.

25 Forecast costs relating to transmission and security of supply impacts of the enhanced RET have been based on the forced LRET scenario. All other costs have been based on the reference case scenario.

- The uptake of the SRES is highly sensitive to the value of the SRES and jurisdictional FITs, so uptake is expected to fall as the value of these incentives falls. However, customers will continue to face a substantial legacy cost for the jurisdictional FITs.
- The total compliance costs of the enhanced RET is expected to increase from $1.78 billion in 2011/12 to $2.20 billion in 2019/20 in 2010/11 dollars, based on the continuation of policy settings as at late June 2011. As a proportion of retail electricity prices, the enhanced RET is forecast to comprise approximately 3% to 4% of the total retail price over the outlook period.

4 Impact of the enhanced RET on emissions levels

This Chapter sets out the Commission's finalised interim advice on the potential impact of the enhanced RET on emissions levels at a national and jurisdictional level. Emissions reductions associated with the LRET and SRES, as well as costs per t/CO2-e for each scheme, have been modelled out to 2020.

4.1 Impact of the enhanced RET on emissions levels

The impact of the enhanced RET on emissions levels in the energy sector was assessed on the basis of the modelled pattern of renewable generation under the LRET and SRES, which is discussed in Chapter 3.

In projecting the level of likely emissions under our modeled scenarios, emissions have been reported in terms of fugitive and combustion emissions from the electricity generation sector in relation to the LRET.[26] It should also be noted that the cost of abatement has been recorded in terms of the annual cost of abatement each year, rather than in cumulative terms.

Emissions abatement has also been determined in relation to the counterfactual case, which has held current and committed levels of renewable generation as at late June 2011 as constant over the outlook period to 2030/31. As a result, the emissions abatement levels and costs of abatement that we have reported do not include the cumulative abatement that may have been achieved prior to late June 2011, for example, under the expanded RET and Mandatory Renewable Energy Scheme. For these reasons, our emissions projections may differ from other projections that may have been made in other modeling reports.

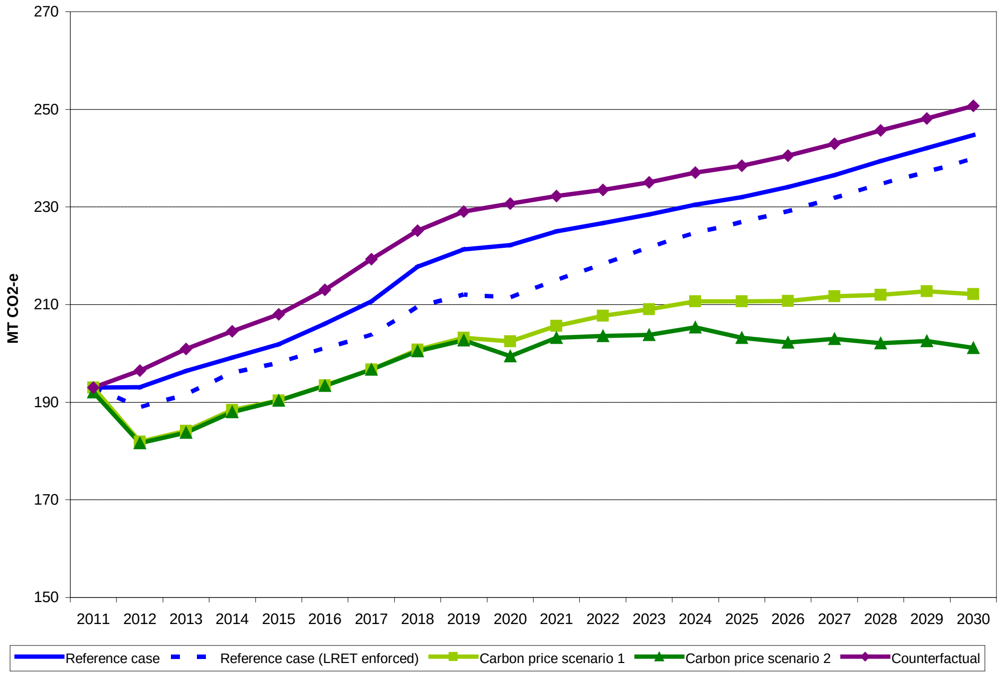
4.1.1 Impact of the LRET on emissions levels

In the NEM, carbon emissions from the electricity generation sector rise steadily under all of the scenarios modelled. Emissions in the reference case rise by around 15% above 2011/12 emission levels by 2020/21. Where the LRET is forced to be met regardless of the penalty price, the level of emissions are only slightly lower compared with allowing only profitable investment to meet the LRET.

Under a carbon emissions price, the increase in emissions by 2020/21 compared to 2011/12 levels is around 4%, which is the result of both increased levels of renewable generation and lower demand in light of higher prices. If there was neither a RET or carbon emissions price in place emissions are forecast to be 20% higher than 2011/12 level emissions, which reflects the low level of renewable generation and lack of a carbon emissions price to reduce the dispatch of high emissions plant. As a result, emissions reductions from generation investment in the NEM due to the LRET are forecast to be approximately 5%.

[26] Fugitive emissions comprise of greenhouse gas emissions from the extraction and distribution of coal, oil and natural gas associated with the electricity generation sector,

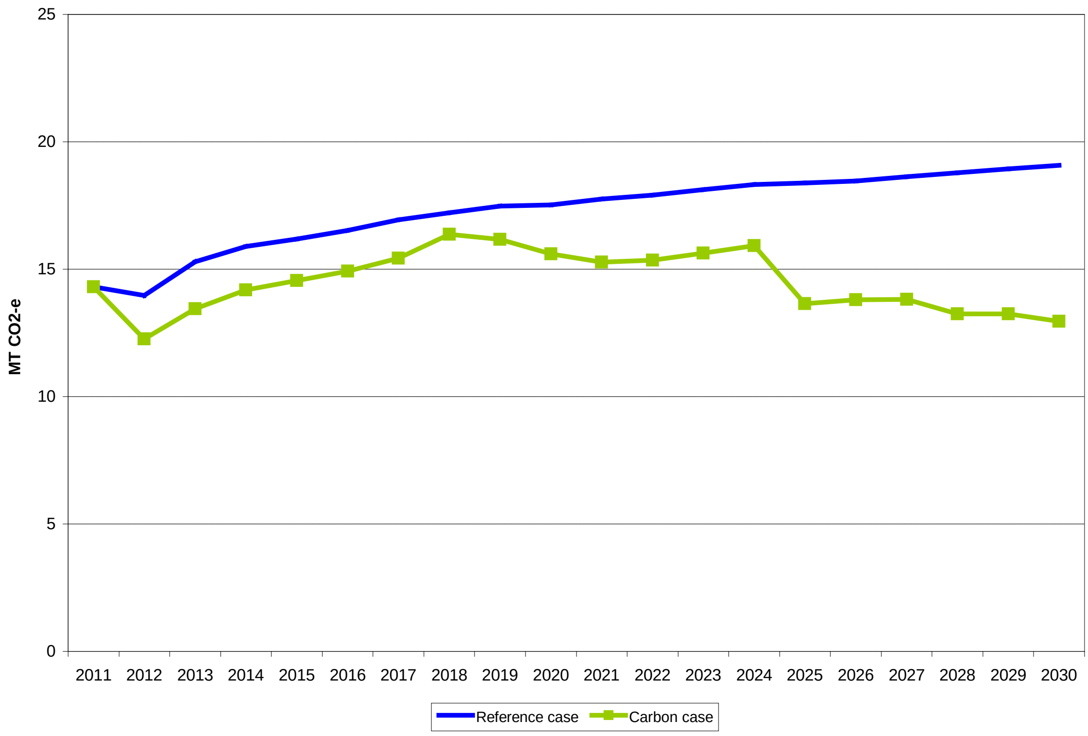
Figure 4.1 Forecast emissions from electricity generation in the NEM



Note: Data represents financial years (e.g., 2011 is 2011/12)

In the WEM emissions under the reference case are 24% higher in 2020/21 compared with 2011/12 emissions levels. Under a carbon emissions price, emissions in 2020/21 are around 9% higher than 2011/12 levels, but are forecast to fall below 2011/12 levels by 2025/26. As committed levels of renewables as at late June 2011 are sufficient to meet the SWIS' pro rata share of the LRET, forecast renewable generation under the reference case and counterfactual are the same. Consequently, the LRET is not considered to lead to any additional emissions abatement relative to the counterfactual in the SWIS.

Figure 4.2 Forecast emissions from electricity generation in the WEM

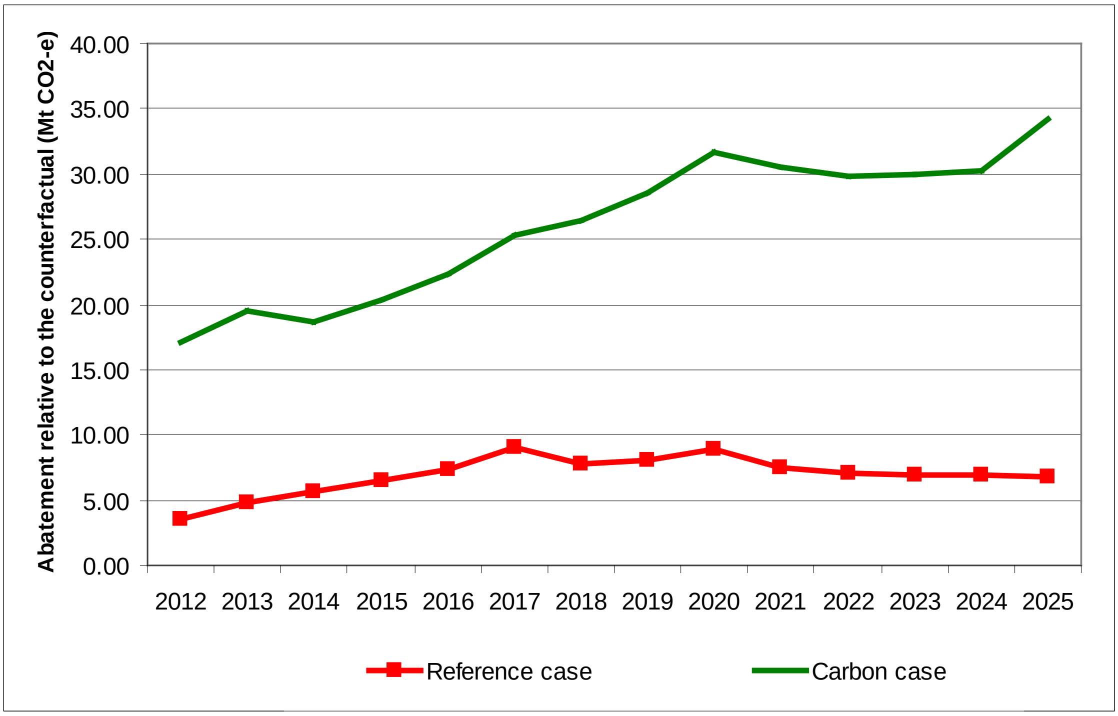


Note: Data represents financial years (e.g., 2011 is 2011/12)

Under all scenarios, it is considered that no existing coal plant is likely to retire. Preliminary analysis of the profitability of coal plants under the modelled scenarios suggests that existing plant are approaching a break even position by the end of the outlook period (2030/31) in the carbon emissions price scenario. This analysis has been based on whether market revenue is forecast to be greater than the sum of operating costs, fuel related expenses and carbon emissions related expenses. No allowance has been provided for capital repayments. Depending on the capital arrangements for each asset there may be major commercial implications earlier than the point where they do not recover operating costs.

Total abatement under the LRET (relative to the counterfactual) is expected to increase to around 9 Mt CO2-e in 2017/18, before declining as incentives for renewable generation under the LRET fall away. Total abatement under the LRET relative to the counterfactual is estimated to be around 61.6 Mt CO2-e between 2012/13 and 2020/21. It has been assumed that the NEM will comprise 86% and the SWIS 6.6% of total emissions abatement, which reflects the relative proportion of these regions to total national demand.

Figure 4.3 Abatement relative to the counterfactual- Reference case and carbon case



Note: Data represents financial years (e.g., 2011 is 2011/12)

Under a carbon emissions price, emissions abatement relative to the counterfactual will continue to increase over the outlook period and by 2025/26 will reach 34.2 Mt CO2-e.

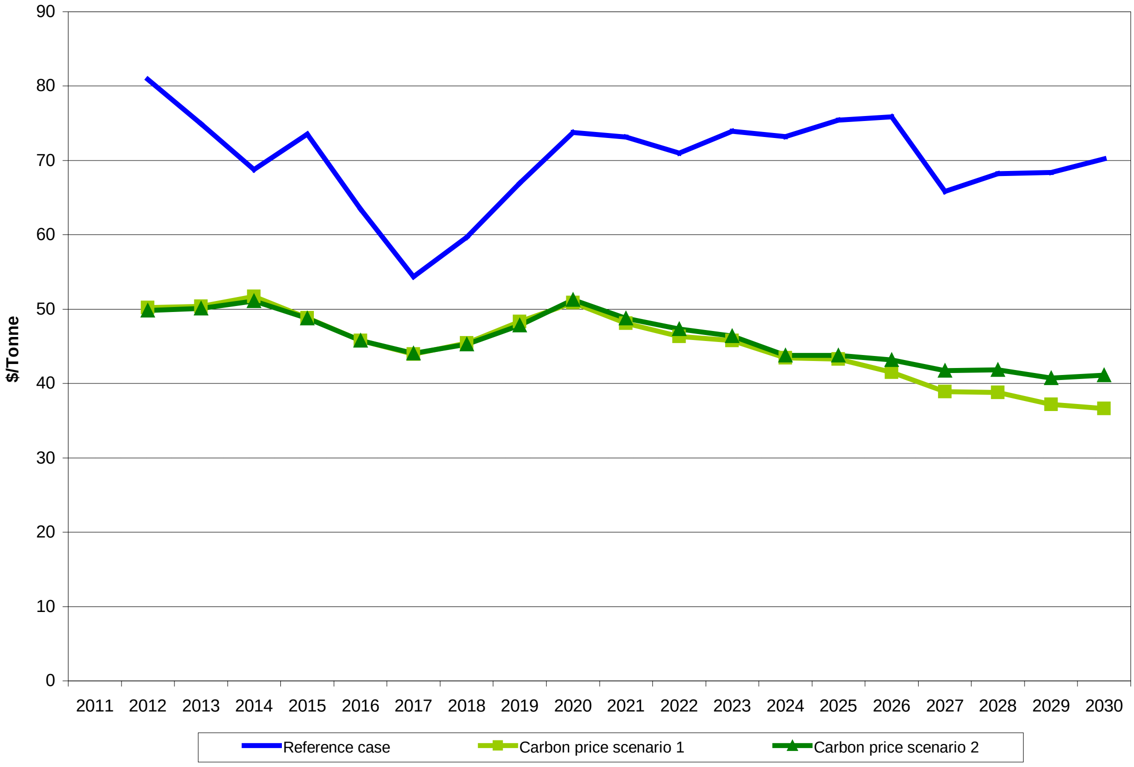
Forecast cost of abatement under the LRET

Our measure of the forecast cost of abatement under the LRET reflects the difference in generation capacity that is installed and the resulting cost under each scenario relative to the forecast level of emissions which are abated. The cost of abatement is calculated as the additional annualised operating and capital costs relative to the counterfactual, divided by the change in emissions.

Under the carbon emissions price scenario abatement costs are affected by more expensive plant, lower demand, and higher levels of emissions abated compared to the reference case. These counteracting influences result in significantly lower costs of abatement under a carbon emissions price compared to the reference case. Less abatement occurs in the reference case, which results in a higher and more volatile cost per tonne of abatement relative to the carbon emissions price scenario.

Costs of abatement are forecast to remain relatively stable under the carbon emissions case at around $50/tonne CO2-e, with a decline in costs from 2020/21 onwards to just under $40/tonne CO2-e by 2030/31. In contrast, costs of abatement under the reference case are forecast to be fairly volatile. Under the reference case costs of abatement are forecast to fall from just over $80/tonne CO2-e to around $55/tonne CO2-e by 2015/16 before increasing to around $75/tonne CO2-e in 2019/20. Costs of abatement are then forecast to remain fairly steady to 2030/31 at around $70 to $75/tonne CO2-e as increased gas plant is installed.

Figure 4.4 Forecast costs of abatement under the LRET



Note: Data represents financial years (e.g., 2011 is 2011/12)

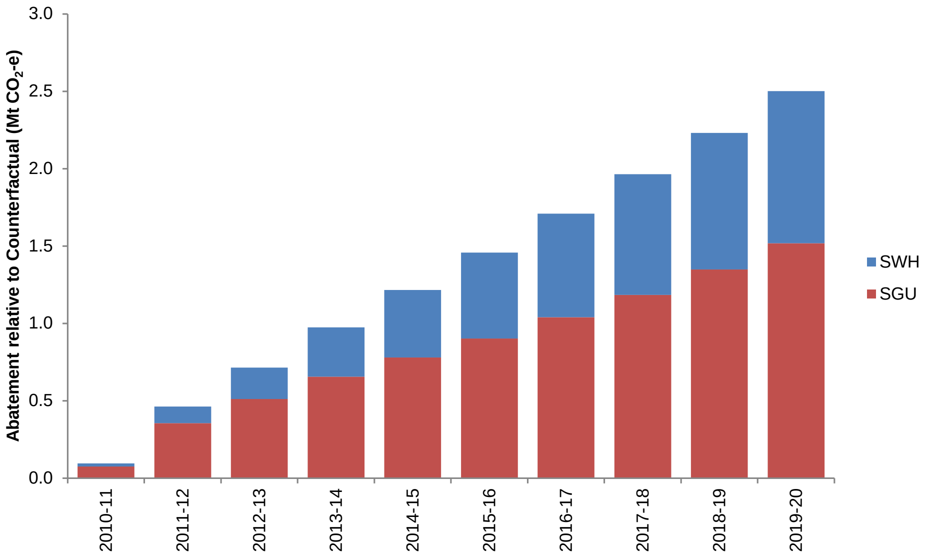
4.1.2 Impact of the SRES on emissions levels

The amount of electricity that the installation of solar PV under the SRES and jurisdictional FiTs is forecast to displace is expected to reach 3170 GWh of electricity by 2020 under policy settings as at late June 2011. The output profile of solar PV is relatively distinct in that they only produce power during daylight hours. The amount of electricity which is displaced from solar PV relates to the avoided household use of electricity from the grid as well as solar PV exports to the grid. Solar hot water is expected to displace 3,220 GWh of electricity by 2020 as a result of the SRES and jurisdictional incentives.

The emissions abatement which is forecast to be produced by the installation of solar PV and solar hot water systems relative to if the SRES was not in place is expected to increase from 0.1 Mt CO2-e in 2010/11 to 2.5 Mt CO2-e in 2019/20. The total emissions abatement under the reference case compared to if the SRES was not in place over 2010/11 to 2019/20 is estimated to be around 13.3 Mt CO2-e.

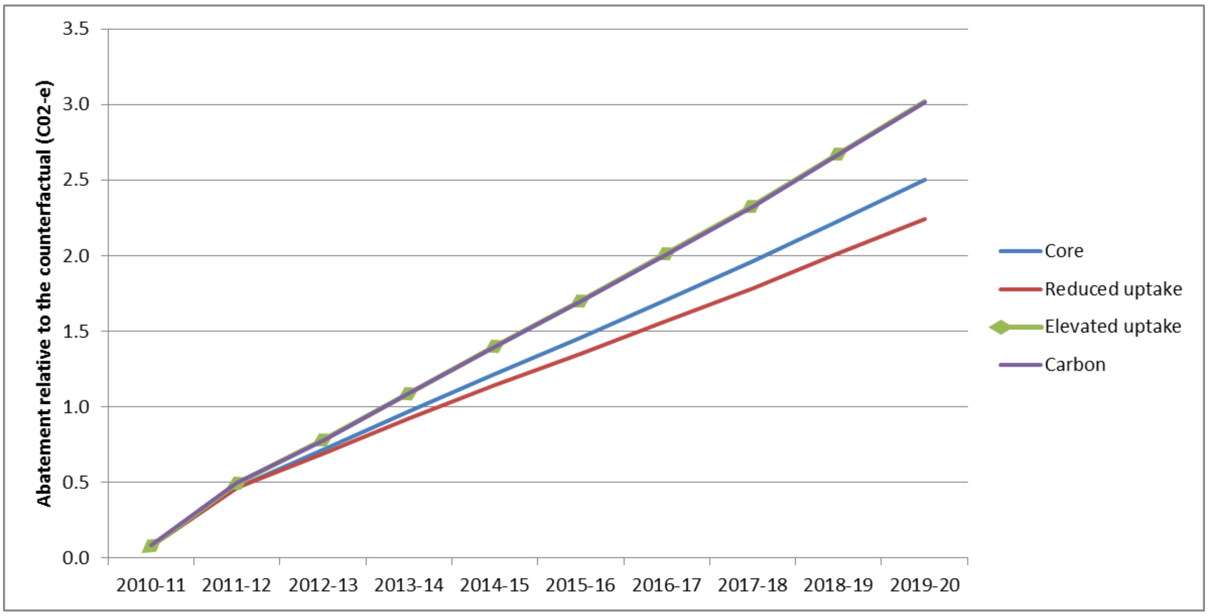
Over the outlook period, installations of solar hot water are forecast to comprise an increasing proportion of emissions abated as incentives for solar hot water are expected to remain relatively stable while incentives for solar PV will fall with the end of the Solar Credits Multiplier and jurisdictional FiTs. As a result, while the number of installations of solar hot water will remain relatively consistent over the outlook period, installations of solar PV are expected to decline over time.

Figure 4.5 Emissions abatement under the reference case compared to the counterfactual



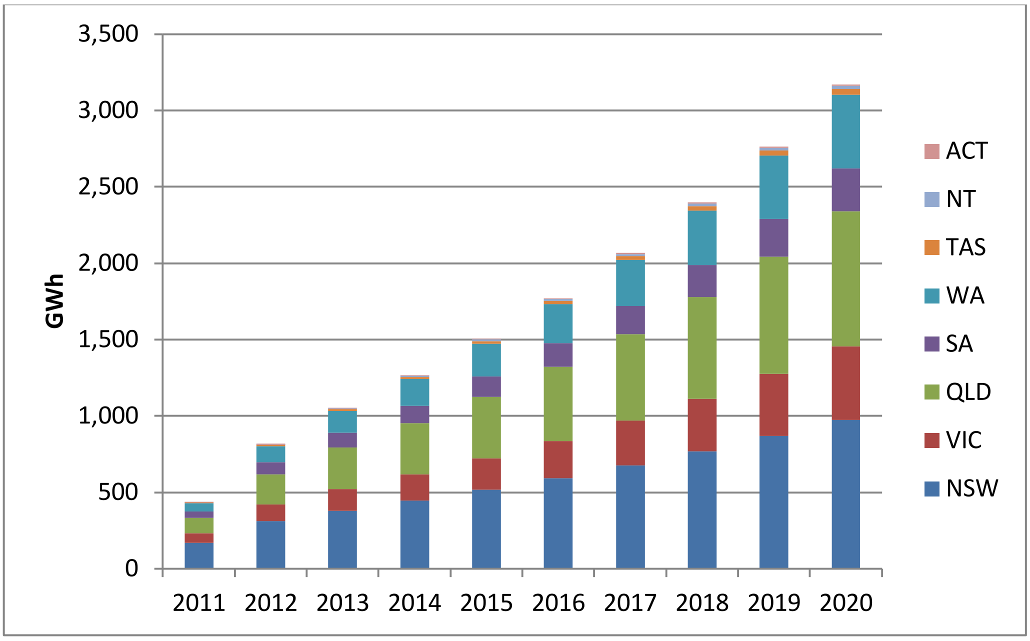
Abatement under the carbon emissions price and elevated uptake scenarios are significantly higher than the reference case at 3 Mt CO2-e by 2019/20. Over 2010/11 to 2019/20, total abatement relative to the counterfactual is forecast to be close to 16 Mt CO2-e under both the carbon emissions price and elevated uptake scenarios. Under the reduced uptake scenario abatement is only slightly lower than the reference case at 2.2 Mt CO2-e by 2019/20, with total abatement over the outlook period estimated to be 12.3.2 Mt CO2-e. Differences in abatement between scenarios reflects differing rates of installation as a result of differences in the Solar Credits Multiplier reductions, jurisdictional FiT scheme rates and caps, retail electricity prices and STC clearing house prices.

Figure 4.6 **Emissions abatement under the SRES by scenario compared to the counterfactual**



The majority of the electricity which is displaced by the solar PV installations will occur in NSW and Queensland by 2020. Factors such as expected retail electricity prices, jurisdictional FiT settings and the level of solar irradiation in each jurisdiction contribute to differences between jurisdictions.

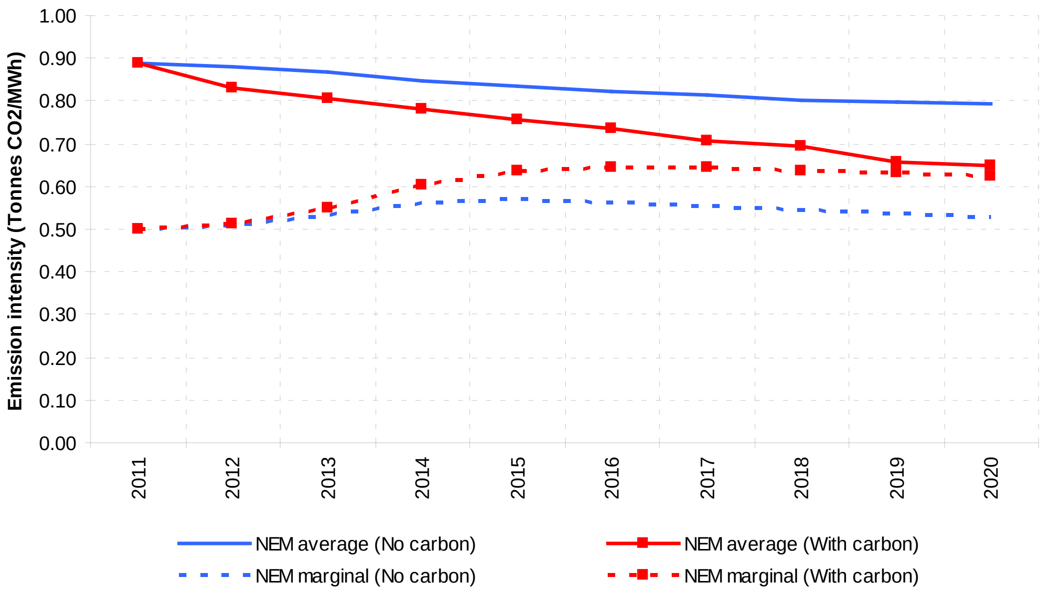
Figure 4.7 **Electricity displaced due to solar PV installations under the reference case**



The level of emissions which are abated under the SRES may be lower than expected, as the emissions intensity of plant which is displaced by solar PV is significantly lower than the average emissions intensity of plant more generally. This occurs as residential solar PV will generate during daytime hours, so will displace mid-merit gas plant rather than higher emissions intensity coal plant which will continue to generate during the night when solar PV does not generate. This highlights that solar PV may result in lower abatement than was anticipated.

Under a carbon emissions price, the difference between the emissions intensity of NEM average and NEM marginal plant is smaller and grows smaller over time as more renewable plant is installed, reducing the NEM average emissions intensity. This occurs as the carbon emissions price alters the merit order of generation and makes coal plant more marginal. As a result the emissions intensity of the plant that solar PV is displacing increases.

Figure 4.8 Comparison of emissions intensity: NEM average emissions intensity and NEM marginal PV



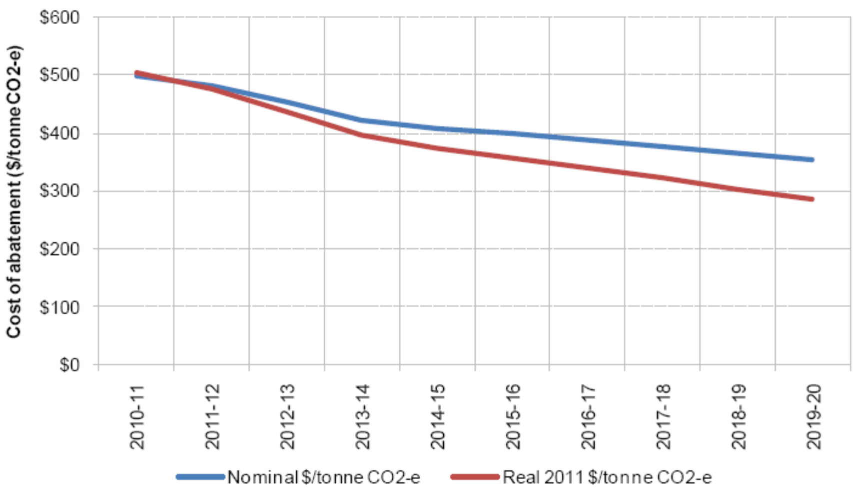
Forecast cost of abatement under the SRES

Calculating the cost of abatement of the SRES itself or of other policies that support solar PV systems such as jurisdictional FiTs is difficult, as it is not possible to entirely disaggregate the abatement or cost that should be attributed to the SRES as distinct from other policies that support solar PV installations or from economic distortions that implicitly subsidise solar PV installations. While the incremental impact of the SRES in addition to other policies can in part be distinguished by comparing scenario results with the counterfactual, as consumers appear to respond to improving paybacks in a non-linear way this may result in overstating the costs of abatement to policies (i.e. the SRES) which are imposed on top of existing policies (i.e. jurisdictional FiTs). In other words, the increase in uptake following the implementation of the SRES is the result of the cumulative effect of incentives provided under both the SRES and jurisdictional FiTs.

For these reasons the costs of abatement have been based on the costs of abatement from solar PV installations, which reflect the cost premium they incur for the economy as a whole when replaced with grid-based electricity. This cost of abatement has been based on an annualised cost of solar PV systems which includes both upfront costs and any ongoing maintenance and replacement costs. The value of the energy component of retail costs is then deducted from this annualised cost, to take into account the electricity which is displaced by the PV systems. This represents the economic resource cost of PV installations, which is then divided by the abatement achieved from the installations to produce a cost of abatement.

Costs of abatement range from around $500/tonne CO2-e in 2010/11 to around $300/tonne CO2-e in 2019/20 in 2011 dollars, indicating that solar PV provides a relatively expensive means of achieving abatement. The cost of abatement falls over the outlook period as system costs decline and energy costs increase.

Figure 4.9 Economic cost of abatement from solar PV - Reference case

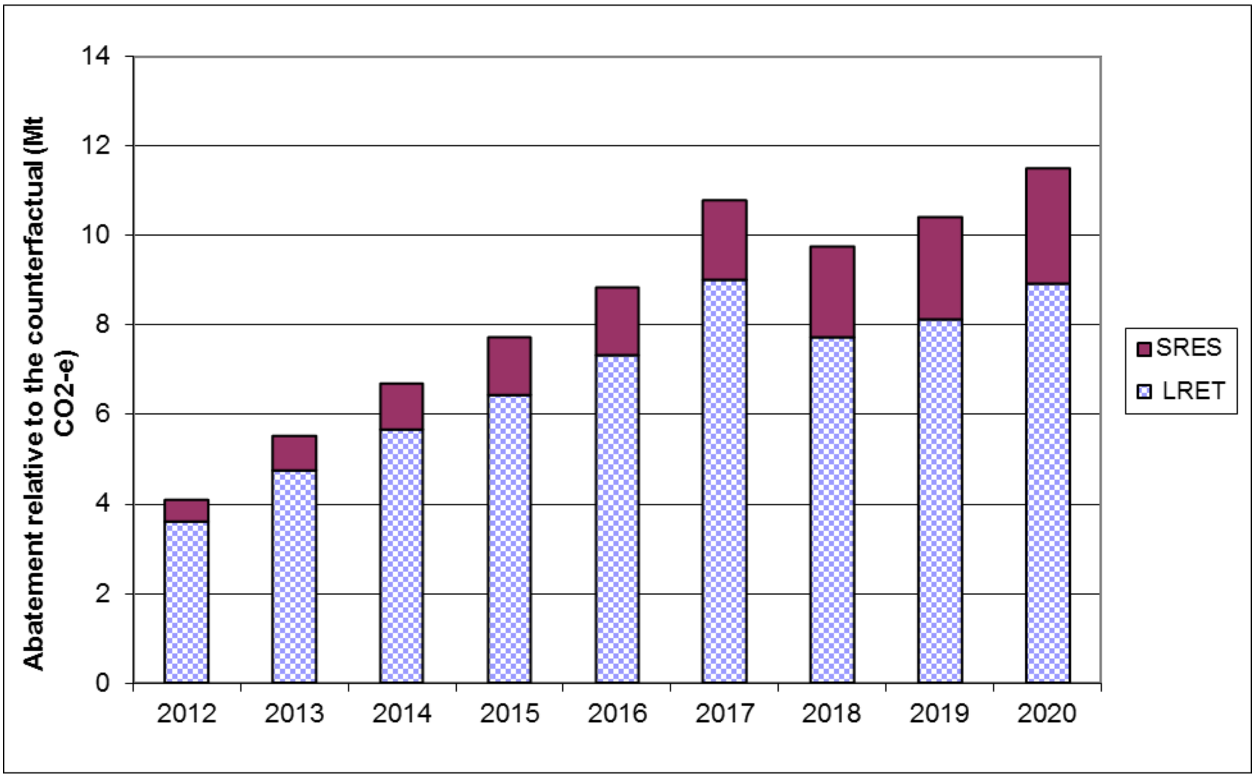


The difficulty with calculating the specific costs of abatement of the SRES or other policies which support solar PV installations imply that consideration of the overall economic costs of supporting solar PV systems in implicit and explicit ways should be given. Not considering the full economic costs of solar PV may result in increasing the overall level of solar PV installations and increasing total economic costs. It may also result in altering the timing of solar PV installations by bringing them forward, resulting in substituting current day more expensive solar PV systems for future lower cost systems as PV system costs are projected to decline significantly in real terms over time.

4.1.3 Total impact of the enhanced RET on emissions levels

Over 2012 to 2020, the enhanced RET is forecast to result in emissions reductions of 75.3 Mt CO2-e compared to if the enhanced RET was not in place. Total abatement relative to the counterfactual is expected to increase from 4.1 Mt CO2-e in 2012 to 11.5 Mt CO2-e in 2020. The LRET is expected to comprise 82% of total expected abatement, while the SRES is expected to comprise 18%. From 2017 onwards abatement is lower under the LRET as incentives to install large scale renewable projects fall away with the impending end of the scheme. In contrast, take up increases under the SRES from 2017 onwards as retail prices increase and expected solar PV system costs fall.

Figure 4.10 Total forecast abatement of the enhanced RET



The modelling by our consultants forecasts that for both the LRET and SRES the new renewable generation will often not displace the highest emitting plant in the NEM (coal fired generation, and particular brown coal generation), but will instead often displace gas fired generation. The effect is particularly pronounced for residential solar PV.

For the overall enhanced RET, we estimate that the average cost per t/CO2 is around $185 by 2020. There is a substantial difference between the abatement costs for the LRET and SRES, with the LRET ranging from around $55 to $80 per t/CO2-e compared to about $300 to $500 per t/CO2-e for the SRES in 2010/11 dollars. The differences in abatement costs between the LRET and SRES highlights the significant difference in value for money which can be achieved from large scale renewable investments compared to small scale renewable investments.

4.1.4 Summary

Our analysis of the enhanced RET on emissions levels indicates that:

- Carbon emissions from the electricity generation sector rise steadily under all of the scenarios modelled, with emissions expected to rise to around 15% above 2011/12 level emissions by 2020/21 under policy settings as at late June 2011.
- Total abatement under the enhanced RET over 2012 to 2020 is forecast at 75.3 Mt CO2-e compared to if the RET was not in place. The LRET is expected to comprise 82% of total expected abatement, while the SRES is expected to comprise 18%.

- The LRET and SRES will often not displace the highest emitting plant in the NEM, but will instead often displace gas fired generation particularly in relation to residential solar PV.
- There is a significant difference in forecast costs of abatement between the LRET and SRES, with costs of abatement under the LRET ranging from around $55 to $80 per t/CO2-e compared to about $300 to $500 per t/CO2-e for the SRES in 2010/11 dollars.

5 Impact of the enhanced RET on security of supply

The LRET modelling shows that between 8000 MW and 9000 MW of new renewable generation capacity will be required in the NEM and SWIS in order to achieve the LRET (where the penalty price constraint is removed). Wind generation is expected to dominate the supply mix due to its position on the cost curve over the period modelled. The variability or intermittency in output of wind means that large volumes can impose significant impacts on the transmission system. This is because intermittency causes rapid increases and reductions in supply which need to be managed by supply or demand responses in real time.

Given the operational characteristics of the NEM and how security of supply is managed by AEMO, the impact of the LRET on security of supply in the NEM will primarily manifest itself as an increased requirement for FCAS and NSCAS. We commissioned ROAM Consulting to undertake modelling to assess these impacts of the LRET on the requirement and costs of FCAS and NSCAS. The results of this modelling are set out in Chapter 3. In this section we explore further some potential issues for security of supply that could arise from the implementation of the LRET, describe in more detail how current arrangements in the NEM and SWIS operate to address them, and identify any areas for possible further improvements.

5.1 Potential issues of the LRET on security of supply

Intermittency is problematic because it impacts the voltage and frequency on the transmission network, both of which are required to stay within certain parameters to ensure demand can be supplied. Electricity is supplied at a given voltage (usually between a nominal value of 220 and 500 kV on Australian transmission networks) and frequency (50 cycles per second or 50Hz). The precise voltage and frequency will vary with supply and demand but needs to be kept within certain bounds to ensure the security of the transmission network is maintained. High volumes of wind generation can have a significant impact on the voltage and frequency of the power system in the following ways:

- Voltages that are too high or too low can result in increased power system losses, overheating of equipment and, at an extreme, causing voltage collapse with consequent loss of customer load,
- Variations in frequency outside strict tolerance bands can increase the risk of damage to generation plant and the potential for the tripping of generation plant and large loads,
- Large penetrations of wind can lower the level of inertia in the system, which amplifies the impacts of supply and demand imbalances on system frequency. The higher the level of system inertia the lower the need for certain types of FCAS (fast raise services)

These impacts are largely managed in the NEM through procurement of FCAS and NSCAS by AEMO. FCAS is procured in real time markets while NSCAS is procured either directly from generators through contracts; or in the majority of circumstances, is provided under the technical requirements for connection in the National Electricity Rules (NER).

In the SWIS the IMO currently procures load following and spinning reserve services from Verve Energy. However, the IMO is currently in the process of developing a Load Following Ancillary Services Market for the SWIS, which would be broadly equivalent to key aspects of the NEM FCAS markets.

5.2 FCAS and NSCAS

5.2.1 FCAS markets

AEMO procures FCAS to maintain system frequency within required limits by ensuring that total generation matches total load in real time. FCAS services are separated into eight separate markets depending on the type of balancing service offered and the different time frames over which particular generators can or are willing to respond to provide these services.

In the NEM, small frequency fluctuations are handled through “regulation” FCAS (two markets for raising and lowering frequency) and large disturbances with the potential to threaten system security are handled through “contingency” FCAS (six markets). Contingency markets are separated into 2 markets for fast raise and lower services and 4 markets that provide for slower response services. If insufficient FCAS services are available, dispatch processes adjust to constrain generation and network flows to ensure the power system continues to operate in a secure manner. Currently in the SWIS FCAS type services are provided by Verve Energy as load following ancillary service (LFAS) and spinning reserve.

Intermittent generation primarily affects the need for regulation services. These services are generally procured from generators with Automatic Governor Capability. This capability allows small but regular frequency fluctuations around the 50Hz standard to be corrected in real time. The flexibility required in meeting the challenges of intermittent generation is in large part met through the inherent design of the NEM, which prices energy and FCAS every 5 minutes (although spot prices are calculated as the average of five minute prices in each half hour).

Under the current “causer pays” cost allocation arrangements in the NEM the cost of regulation FCAS are split between generators and customers, and wind generators are required to fund these costs based on their contribution to frequency deviations. In the SWIS the costs of ancillary services are not specifically allocated to causers, but are averaged across generators and consumers more broadly.

5.2.2 Procurement of NSCAS

AEMO procures NSCAS to manage voltage on the network and ensure it is kept within acceptable limits. Voltage is primarily controlled through provision of reactive power by generators. This is usually provided as part of a generator's normal obligations under the NER, although TNSPs currently contract for reactive power from generators in some areas of the power system where such services are considered necessary for managing system security.[27]

Large generators are the key source of reactive power in the NEM. Most conventional wind generators are not technically capable of contributing to voltage control and because high penetrations of such technologies were not envisaged when the technical standards were originally developed, the NER do not require wind generators to have such capabilities. This may become problematic over time as wind generation reaches higher levels of penetration.

In a study performed for the South Australian Government, the Electricity Supply Industry Planning Council (ESIPC) in 2004 found that network security may be at risk where wind exceeds 20 per cent as an overall proportion of generation capacity. [28] This work was done in the context of South Australia which already has, on a regional basis, one of the highest concentrations of wind generation capacity relative to demand anywhere in the world (approaching 20 per cent). This compares with approximately 2 per cent elsewhere in the NEM. The AEMC's LRET modelling shows that wind will make up approximately 30 per cent of generation capacity in South Australia under the reference case scenario.

Additional license conditions were introduced by the South Australia Government in 2005 to address higher levels of wind penetration in this state. Under these conditions new wind generators locating in South Australia with a nameplate rating of greater than 5 MW are required to be able to do the following: absorb or produce reactive power; ride through severe network disturbances; and smooth fluctuations in output to manage variability. While such requirements do not currently form part of the NER, they can be readily met by many of the newer wind generation technologies entering the market, such as variable speed double fed induction generators (DFIGs). Further, existing or older wind generators can improve their ability to produce or absorb reactive power by retrofitting with equipment such as Static Var Compensation (SVC). More detail on these issues can be found in ROAM’s modelling report.

5.3 Assessment of the existing arrangements under the NER

The NEM has some inherent strengths and flexibility in managing intermittency. It is an energy only market operating under a bid based security constrained dispatch, which co-optimises the costs of meeting demand and maintaining system frequency. Market prices are calculated every five minutes, which allows generators with fast ramping capability, such as hydro and gas fired generation, to respond quickly to market signals to correct imbalances caused by variability. AEMO also procures a range of FCAS for managing supply and demand imbalances within 5 minutes.

There have been some important recent developments in NEM dispatch arrangements to accommodate increasing levels of wind generation. In particular, in 2008 the NER

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27 Under the National Electricity Rules, generators do not receive any specific payment for the provision of reactive power.

28 Energy Supply Industry Planning Council, 2005, “Wind report to ESCOSA” April. Available at: http://www.escosa.sa.gov.au/Projects/17/2005-wind-generation-licensing.aspx

was changed to require wind generators to be integrated into the NEM dispatch process, which allows them to be controlled by AEMO when constraints bind, and importantly, also allows their contribution to the need for FCAS to be recognised in subsequent cost allocation. [29]

A further important reform is the implementation of a new centralised wind energy forecasting system in the NEM in 2008. This forecasting system uses a combination of real time measurements, historical information, weather forecasts, terrain data, and turbine availability to forecast and publish wind generation from 5 minutes ahead to up to 2 years ahead (60 minute resolution), with capability for identifying daily wind patterns for individual wind farms.

The WEM is currently in the process of developing a more competitive market for the provision of load following and spinning reserve in the SWIS, which is anticipated to commence operation in 2012.

5.4 Implications of the LRET on FCAS and NSCAS

ROAM found that in absolute terms FCAS costs were unlikely to make up a significant overall proportion of total energy costs (energy settlements range from about $12 to $20 billion under the three core scenarios modelled). Nonetheless, as set out in Figure 5.1 below, meeting the LRET could increase the FCAS requirements (predominantly regulation) from about $10 million in 2010/11 to over $200 million in the NEM by 2019/20 in 2011 dollars. Under the counterfactual scenario, FCAS requirements are forecast to be lower compared to the reference case. There is no difference in LFAS costs between the reference case and counterfactual in the SWIS (therefore no LFAS cost increase due to the LRET). Of note however, is the significant increase in LFAS costs over 2010/11 to 2019/20 from $32 to $160 million (assuming a market for LFAS is introduced) in 2011 dollars that is forecast if a carbon emissions price scenario is assumed. These represent considerable increases in costs when compared to current levels of FCAS and LFAS costs in the NEM and SWIS.

Under the causer pays methodology, the increase in FCAS cost would largely be targeted towards renewable generators in the NEM, while LFAS costs are socialised more broadly in the SWIS. ROAM found that these FCAS costs for wind generators could be quite considerable in the context of their overall costs, with FCAS costs for wind generators forecast to increase from about $0.41/MWh in 2010 to $8.30/ MWh by 2020 in 2011 dollars in the NEM reference case. Similar FCAS costs for wind generators were also forecast under the carbon emissions price scenario.

In the SWIS, FCAS costs for wind generators are forecast to increase from $0.40/MWh in 2010 to about $2/MWh by 2020 in 2011 dollars under both the reference and counterfactual cases. Where a carbon emissions price is assumed, FCAS costs for wind generators increased much more significantly, to about $6/MWh by 2020 in 2011 dollars, as a consequence of significantly more wind capacity entering under this scenario.

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29 See "National Electricity Amendment (Central Dispatch and Integration of Wind and Other Intermittent Generation) Rule 2008 No.2 "

Figure 5.1 ROAM's modelled FCAS and NCAS requirements for NEM and SWIS

	2010-11 ($Millions pa)		2019-20 ($Millions pa)		Wind FCAS costs ($MW/h)	
NEM	**FCAS**	**NCAS**	**FCAS**	**NCAS**	**2010**	**2020**
Reference	10	49	204	89	0.41	8.30
Counterfactual	10	49	5	53	0.41	0.17
Carbon	10	49	177	88	0.41	6.20
SWIS	**LFAS**	**NCAS**	**LFAS**	**NCAS**	**2010**	**2020**
Reference	22	49	58	50	0.42	2.24
Counterfactual	22	49	58	50	0.42	2.24
Carbon	32	49	160	52	0.42	5.92

Note: All figures quoted in this table are in Real 2011 dollars

One important factor to bear in mind is that ROAM used historical bids in its dispatch modelling, which may not capture the dynamics of FCAS and LFAS markets (shortly to be introduced in the SWIS). That is, it is unclear how a much larger FCAS requirement, and subsequent FCAS prices, may attract new entrants to provide such services and the extent to which a new market structure may affect bidding behaviour. An effectively working market in FCAS and LFAS may temper the high costs predicted in the ROAM modelling, which points to the importance of having such markets in place.

There is currently no market for ancillary services in the SWIS as yet, although the IMO will introduce one shortly. However it is not clear at this stage whether causer pays arrangements will be implemented in the same way as in the NEM. This may become an issue of some importance given the significant forecast increase in regulation FCAS requirements. While causer pays arrangements may impose a significant cost on wind generators, arguably they are best able to manage such costs (for example, through better forecasting methodologies). Without appropriate price signals wind generators may not efficiently manage their impacts on the transmission network over time.

The modelled NSCAS costs in 2019/20 were found to be very small, despite the relatively extreme assumption in the modelling that outside South Australia new entrants would locate in weak parts of the grid and be of the older wind turbine technology types. This result reflects in part the fact that no coal fired generation is expected to retire over the modelled period (and therefore substantial inertia remains in the system) and the strict technical standards for renewable generators in South Australia, where a significant proportion of the overall renewable requirement to meet the LRET will be located. As noted above, these requirements were introduced by the South Australian Government as special license conditions in 2005 to address increasingly high levels of wind penetration in that state.[30]

30 Essential Services Commission of SA, "Licence Conditions for Wind Generators – Final Decision", May 2010, available on www.escosa.sa.gov.au

5.5 Conclusions and recommendations

Our modelling on the potential impacts of the LRET on security of supply show that such costs are not anticipated to be material in an absolute sense. While regulation requirements are set to increase significantly, compared to what is currently required, it is anticipated to only make up only a few percent of total energy revenues by 2019/20. NSCAS costs are expected to be much smaller still. We expect that provided there are no barriers to service provision that the FCAS and LFAS markets operating with causer pays arrangements will help moderate any future increases in regulation costs.

Regarding NSCAS, given the quantum of these costs it does not appear that any changes to the NER are necessary to strengthen technical requirements outside South Australia. It is also likely that with innovation and associated reductions in costs new entrant renewable generators will increasingly have as standard equipment the reactive power, voltage control and other capabilities that would minimise their impact on the network. However, given the uncertainties surrounding a modelling task such as this, in particular assumptions regarding the retirement of conventional fossil fuel generation capacity, it is important that this issue continues to be monitored. We note in this regard that an investigation of future NSCAS requirements will be a key issue for examination by AEMO in its 2011 NTNDP consultation.[31]

The AEMC is keen to receive feedback on the analysis by ROAM Consulting and will take this into account in considering whether there may benefits in assessing options to better ensure security of supply as a result of the LRET.

31 AEMO, 2011, 'National Transmission Network Development Plan: Consultation Paper 2011', 31 January.

6 Beneficiaries under the SRES

From our review of the available literature it appears that there has been relatively little analysis of the groups of energy consumers that are benefiting from the SRES (and jurisdictional FiTs), and conversely which groups of energy consumers are not benefiting. Such an analysis can be quite important for policy design as it may help policy makers understand the distributional impacts of their policy decisions. Therefore, we commissioned Seed Advisory to undertake a historical analysis of relationships underlying successful applications for the SRES, by comparing all such applications on the ORER database with census data and other demographic indicators at a postcode level.

This analysis provides information about the characteristics of the energy consumers such as age, average income, and education level in postcodes that have benefited from the SRES and those that have not. At this stage we have not sought to use this analysis to directly inform the projections of the future take-up of the SRES, for which we have used modelling by ACIL Tasman, as discussed in Chapter 3. The analysis by Seed Advisory would need to be extended to consider in more detail the interaction of different demographic factors before it could be robustly used for such forecasting.

Seed Advisory's study has the advantage of using ORER's data nationally, from the inception of the RET and has combined it with a wide range of demographic variables to identify a broader set of relationships. We are not aware of such a study having been previously done on this scale in Australia. Previous published studies have analysed and identified relationships with subsets of the ORER data and specific demographic variables, but were generally narrowly focussed and investigated a specific relationship type. Hence, for this study the variables to consider and relationships to test had to be determined, with a focus on univariate rather than multivariate analysis.[32] More multivariate analysis would be done if there was earlier research that could confidently develop relationships to test with multivariate analysis.

In this section we explain the methodology used for the analysis. We then discuss some of the key results of the analysis, including identifying the demographic characteristics of those who have benefited and not benefited from the SRES. We then discuss in more detail the strength of the relationship between SRES uptake and key demographic factors. Finally, we discuss some further analysis of these issues that could be undertaken.

6.1 Methodology

For its analysis Seed Advisory used the following information:

- ORER data on installations of solar PV, solar hot water systems and eligible small generating unit (SGU) wind installations for the period from 2001 to mid-March 2011;

32 Univariate analysis tests the strength of a relationship between two variables. On the other hand, multivariate analysis tests the strength of the relationship between a range of variables and one single variable, e.g. a range of demographic characteristics and the uptake of the SRES.

- 2006 Census data and the 2006 Socio-Economic Indexes from Areas (SEIFA) from the Australian Bureau of Statistics (ABS). Given the large number of variables in the Census we made an initial decision to exclude variables that appeared to be very unlikely to explain the uptake of the SRES, e.g. whether a member of the population was male or female;
- taxation data for 2006/07 from the Australian Taxation Office;
- three economic series from the Reserve Bank of Australia, including GDP, CPI and the unemployment rate; and
- payback data for solar PV installations, provided by ACIL Tasman.

After the above data was reviewed and cleaned, the data was linked together by postcode, time period, size of installation and jurisdiction for the SRES uptake. This allowed Seed Advisory to assess the relationship between the uptake of the SRES and a range of demographic variables. Initially Seed Advisory focussed only on analysing relationships between each variable and the uptake of the SRES, before moving on to assessing the relative impact of a range of variables. Given the limited similar research we were not in a position to develop specific relationships between the SRES uptake and the various demographic variables (which is a standard approach to this type of analysis) to test the overall best combination of variables to explain the SRES uptake. Instead we focussed on getting a better understanding of the relationships between each variable and the SRES uptake.

The relationships resulting from the initial analysis were classified into categories. Variables were excluded where the relationship with penetration (measured by installations per 1,000 dwellings) has an R-squared of less than 0.7.[33] An R-squared value of 0.7 was chosen as it shows a reasonably strong relationship between the two variables. In further classifying the relationships, the following sub-categories were used:

- strong positive - the slope of the relationship (and the correlation) is positive and the slope is such that as the average value of the independent variable increases from decile one through to decile ten the penetration rate increases by more than its average value;
- positive - the slope of the relationship (and the correlation) is positive and the slope is such that as the average value of the independent variable increases from decile one through to decile ten the penetration rate increases by between 50% to 100% of its average value;
- flat - the slope of the relationship is such that as the average value of the independent variable increases from decile one through to decile ten the penetration rate increases or decreases by between 0 - 50% of its average value;
- negative - the slope of the relationship (and the correlation) is negative and the slope is such that as the average value of the independent variable increases from

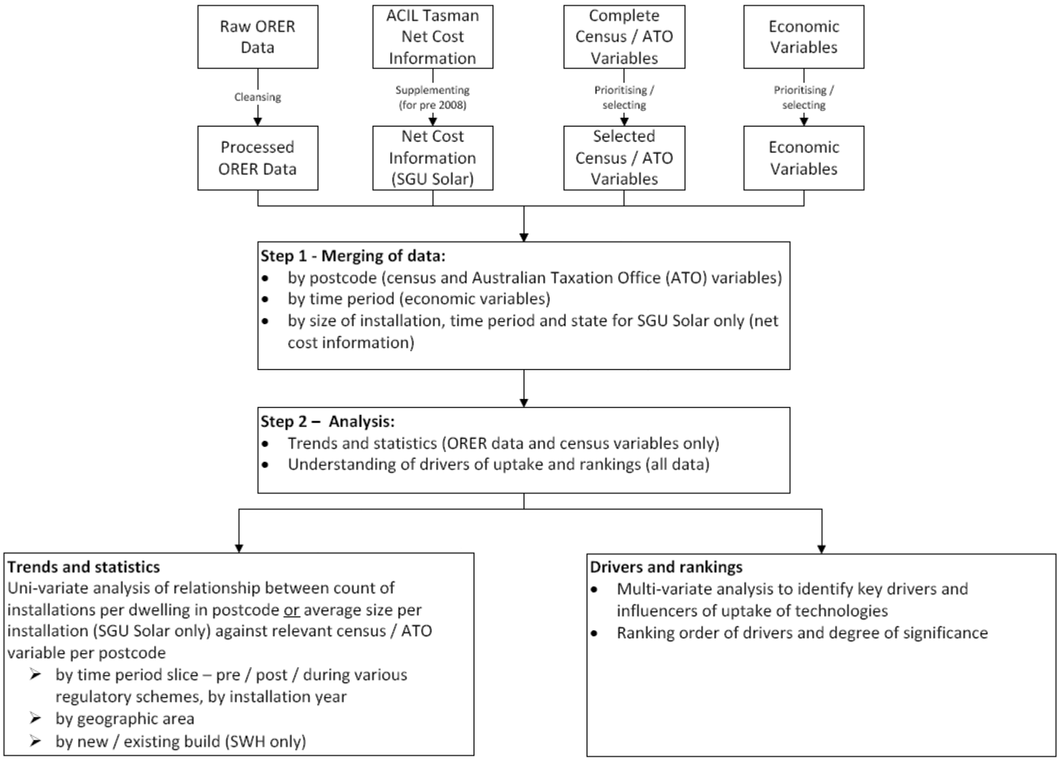
33 R-squared is a statistical measure of the strength of a relationship between two variables. The closer the R-squared values are to 1 the stronger the relationship and conversely the closer the R-squared values are to 0 the weaker the relationship.

decile one through to decile ten the penetration rate decreases by between 50% to 100% of its average value; and

- strong negative - the slope of the relationship (and the correlation) is negative and the slope is such that as the average value of the independent variable increases from decile one through to decile ten the penetration rate decreases by more than its average value.

Figure 6.1 summarises the methodology used by Seed Advisory.

Figure 6.1 Seed Advisory's methodology



6.2 Key observations on historic SRES uptake

The penetration of solar PV and solar hot water installations, expressed as the number of installations per 1,000 dwellings, varies widely by postcode across Australia, as Figure 6.2 and Figure 6.3 illustrate. Generally it is areas of lower population density that have higher uptake.

Figure 6.2 Penetration of solar PV by postcode, installations per 1000 dwellings

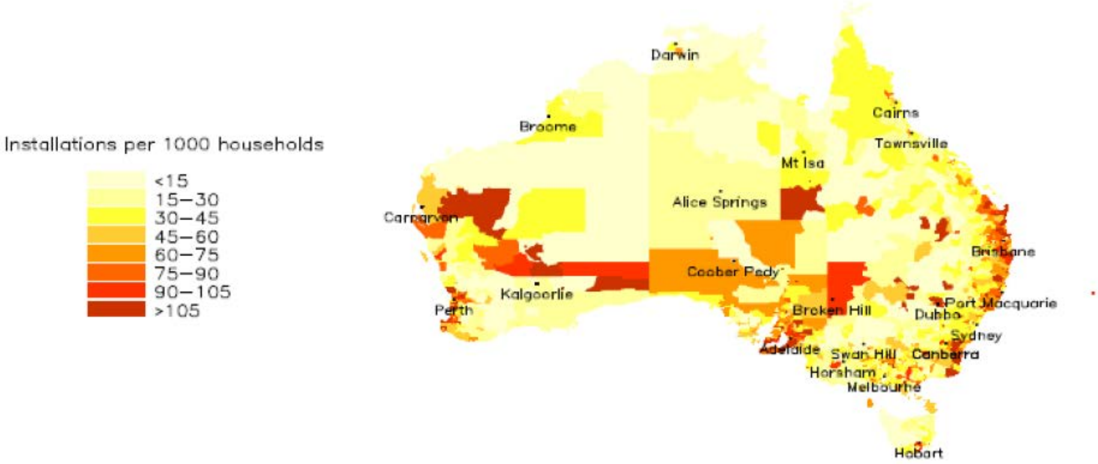
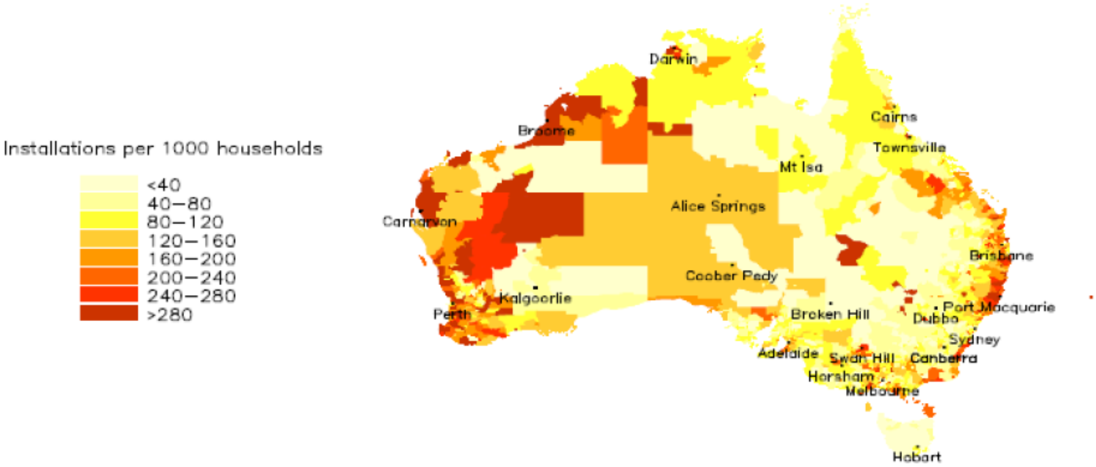


Figure 6.3 Penetration of solar hot water systems by postcode, installations per 1000 dwellings



In explaining this variation, the results show that:

- There are strong linear relationships between the penetration of solar PV and solar hot water systems and around a third of the Census and Australian Taxation Office (ATO) variables included in the analysis.
- There are a number of non-linear relationships that vary in significance, but which may be important in understanding the characteristics of the uptake of small scale renewable technologies. These include some income variables, as well as the ABS's 2006 Socio-Economic Indexes from Areas. The ABS Socio-Economic Indexes suggest that penetration rates are lower for the lowest decile of postcodes ranked by the index value, suggesting that the lowest decile socio-

economic groups may not have benefited from existing incentives to install small scale renewable energy technology.[34]

- There are relatively few variables at a national level that vary with the average size of installation of solar PV or solar hot water systems and none with a relationship that is consistent across more than a few states.
- Significant relationships between penetration of small scale renewable energy technologies and the characteristics of postcodes with high (or low) penetration differ from state to state and across time.
- The preliminary analysis of relationships at the multivariate level suggests that different relationships may be significant when the variables are tested together. There are relatively few commonalities between the truncated results of the preliminary multivariate analysis and the significant relationships identified at the univariate level.

6.3 Analysis of historic SRES uptake by consumers

As at mid-March 2011, there were just fractionally under 40 solar PV installations for every 1,000 dwellings Australia wide (“the penetration rate”), calculated from the number of dwellings in the 2006 Census.[35] For solar hot water heaters, there were approximately 88 solar hot water heaters for every 1,000 dwellings nationally. The highest penetration areas include a number of remote areas in Western Australia, South Australia and western NSW,[36] coastal areas from north of Port Macquarie to north of Brisbane and north of Perth, and Hobart and its surrounds, including Bruny Island.

6.3.1 Characteristics of areas with higher penetration of small scale renewable technology

The results suggest that the penetration is higher in postcodes where there is:

- a higher share of the population falling in the 35 to 74 years age group;
- a higher share of detached and semi-detached houses that are owned or being purchased;
- a higher number of bedrooms for a dwelling;
- a higher proportion of dwellings with young children;
- a higher number of cars per household;
- relatively low population density; and

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34 However, there is evidence that the lowest decile income group includes a significant proportion of people who may be in that decile for only a short period of time, or in circumstances that does not reflect their wealth or financial situation. For example, a person taking time off between two jobs or on a career break at the time of the Census may be in this decile.

35 ACIL Tasman's analysis of the penetration of solar PV installations outlined in Chapter 3 only assess "eligible" dwellings (i.e. detached and semi-detached houses) so its equivalent percentage penetration rates are lower.

36 Penetration in these areas may be the result of a relatively small number of dwellings at the individual postcode.

- a higher proportion of the population with an income in the range between $1,000 to $1,700/week.[37]

This set of characteristics has not been tested for their correlation with each other, so it cannot be concluded that all postcodes with high levels of penetration have energy consumers which are characterised by all of these features.

6.3.2 Characteristics of areas with lower penetration of small scale renewable technology

The results suggest that the penetration is lower in postcodes where there is:

- a higher share of the population falling in the 20 to 34 years age group;
- a higher share of people with poor English; and
- a higher proportion of family or households with weekly gross income of $1,700 and above.

The preferred measures for socio economic status, the ABS's 2006 Socio-Economic Indexes from Areas, suggest low socio-economic areas have not benefited. Postcodes with the lowest index scores, indicating relatively high levels of socio economic disadvantage at the postcode level have, on average, low levels of solar PV penetration relative to the national average.

6.3.3 Areas with weak relationships

A number of variables had weak or flat relationships with solar PV penetration. An example of a weak relationship found by Seed Advisory was between the number of solar PV installations per 1,000 dwellings and the share of most likely dwellings (detached and semi-detached single family dwellings) with broadband. This was contrary to our expectations, as this variable was included in an attempt to identify a representation of "early adopter" behaviours. In addition to this, other variables which had a flat relationship with respect to penetration of solar PV include:

- the proportion of people who live at the same address five years ago;
- the proportion of machinery operators and drivers in the mostly likely age range (35 to 74 years);
- the percentage who are unemployed;
- income (median household);
- average net capital gain; and
- the proportion of people employed in education and training services and in the likely age range (35 to 74 years).

For solar hot water systems, variables which had a flat relationship with respect to penetration include:

- the proportion of people who live at the same address a year ago;

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37 All dollar values in this Chapter are expressed in 2006 dollars, unless otherwise specified.

- the proportion of clerical and administrative workers in the most likely age range (35 to 74 years);
- the percentage who are unemployed;
- the proportion of managers in the most likely age range (35 to 74 years);
- the proportion of people employed in health care and social assistance and in the likely age range (35 to 74 years); and
- average net capital gain.

6.4 Relationships between penetration and key demographic factors

6.4.1 Defined income bands: Positive relationship with penetration

Significant positive relationships were identified between penetration and the proportion of families or households in a postcode with:

- weekly gross incomes between \$250 – \$649; and
- weekly gross incomes between \$1,000 – \$1,699, the cut-off point being just below the eligibility threshold for government assistance towards the capital cost of the installation under the Solar Homes and Communities Plan (SHCP) program.

Postcodes characterised by the proportion of households described as having sufficient income to receive government assistance under the SHCP program (i.e. all households with household income over \$1,000/week) display no significant linear relationship with penetration. These relationships are shown in Figure 6.4, Figure 6.5, and Figure 6.6.

Figure 6.4 National penetration of solar PV by postcode, selected incomes variables by decile, number of installations per 1000 dwellings

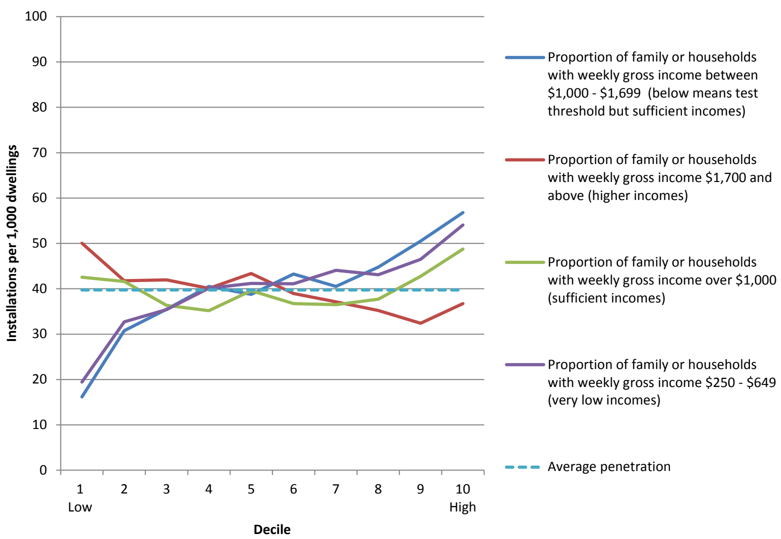


Figure 6.5 Penetration of solar PV by postcode and state, selected incomes variables by decile, number of installations per 1000 dwellings

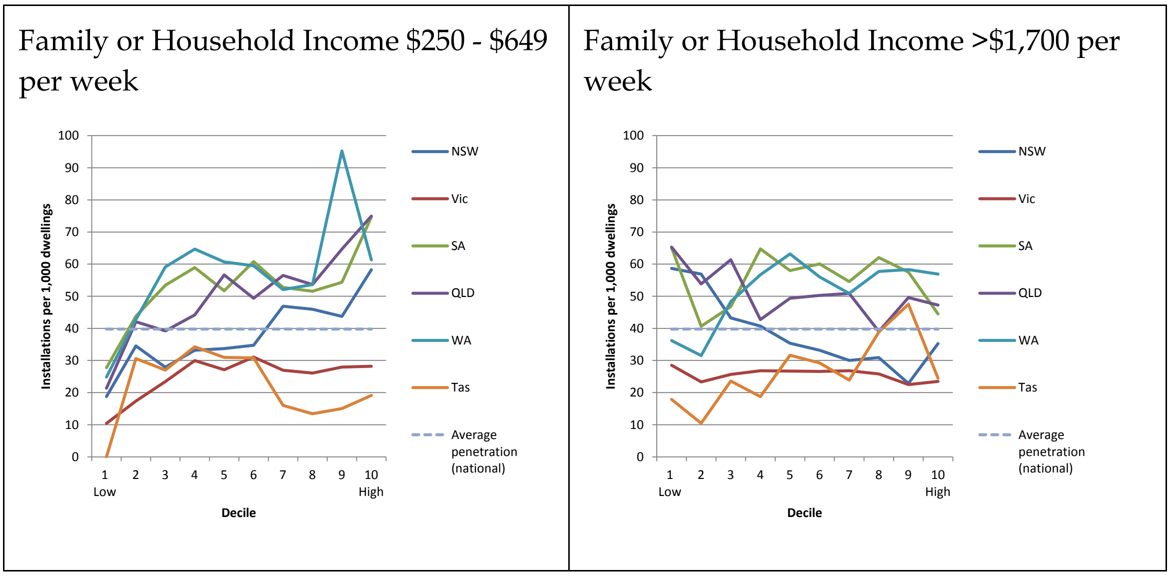
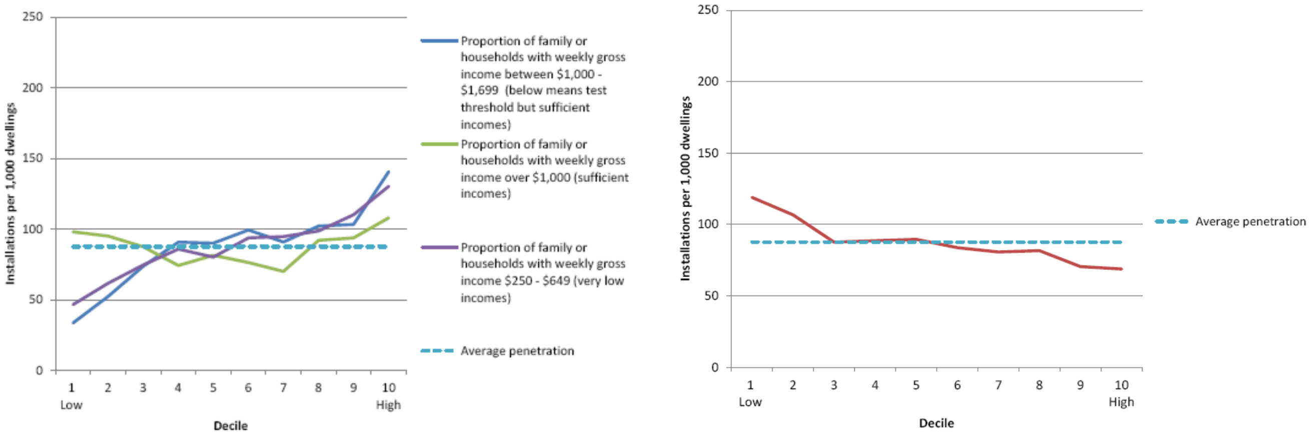


Figure 6.6 National penetration of solar hot water systems by selected household income measures, number of installations per 1000 dwellings



These results cannot be interpreted as meaning, for example, that people with low incomes are more likely to install solar PV panels than other people. First, postcodes are not people. The values found in Seed Advisory's analysis are averages for a group of postcodes, but we cannot identify whether, in a postcode with a low (or high) average income, low (or high) income families have installed solar PV. However, the analysis does show that:

- The penetration of solar PV panels is higher as the share of the postcode's population with low incomes increases from around 7 per cent in the lowest (first) decile to between 22 per cent and 50 per cent in the highest (tenth) decile. The results show a similar effect as the share of the population with a weekly gross income of between $1,000 and $1,699 increases.

- The selected income bands appear to be independent, i.e. the characteristics relate to different postcodes, not to postcodes where two of the groups are simultaneously represented. The results appear to suggest that, as the level of homogeneity (measured by the proportion of the postcode population in the $250 to $649/week or $1,000 to $1,699/week groups) increases, so does penetration.
- The reverse appears to be the case for postcodes with an increasing proportion of households with an income higher than $1,700/week – the higher the share of this group in the postcode population, the lower the penetration.
- These results relate only to part of the distribution of incomes. Other parts of the distribution of incomes (i.e. below $250/week or between $650 and $999/week) appear to have no significant relationship with penetration.

6.4.2 Median Family Income: Negative relationship with penetration

In contrast to the positive relationships between the two income band variables (i.e. weekly gross incomes between $250 to $649 and between $1,000 to $1,699), three direct income measures show a significant negative, but not strong negative relationship between the value at a postcode level and penetration – Median Family Income, Median Household Income and Average Salary or Wages. As average postcode Median Family Incomes, Median Household Incomes and Average Salary and Wages increase, the number of solar PV installations per 1,000 households falls.

Figure 6.7 shows that:

- At the highest (tenth) decile, the analysis suggests that SRES uptake has not been disproportionately dominated by participants in postcodes with higher average incomes. Higher income postcodes have, on average, fewer installations per 1,000 households than the national average. This finding can be extended to postcodes with higher wealth and may reflect the operation of the eligibility criteria on uptake of small scale renewable energy technologies. Higher income groups were excluded from eligibility for Federal Government assistance under the various programs from 2001.[38]
- Australian data on the distribution of wealth suggests that wealth and income are reasonably well correlated.
- Seed Advisory has tested the relationship between penetration and average imputation credits, which are a proxy for share ownership, which is regarded as being reasonably well correlated with wealth.[39] Imputation credits do not have a significant relationship, either positive or negative with penetration of solar PV.

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38 Note, however, that the income ranges corresponding to the two highest deciles of median family income are below the eligibility cut off. Growth in median household incomes between 2006 and 2008 may explain part of this difference.

39 Bureau of Infrastructure, Transport and Regional Economics (BITRE), 2008, Household wealth. Information Paper 63, Canberra ACT. BITRE (2008) estimates that the top wealth decile in Australia held 69 per cent of all household holdings of shares and trusts in 2003-04. Their analysis also suggests income as reasonably strongly correlated with wealth and housing values, reflecting the significance of housing investments in household wealth in Australia. Seed Advisory also tested average gross interest and average net capital gains declared, based on ATO data. See Appendix A for details of the variables included.

Further, there are only marginal differences between average national penetration rates and penetration for postcodes ranked by imputation credits received, taking into account the estimated standard errors, except for the highest (tenth) decile, where average penetration is lower than the national average and the difference is statistically significant.

- Looking at deciles 2 to 8, which include postcodes in which 70 per cent of total solar PV installations have been made, it is worth noting that the difference in the average value of the variable from decile to decile is small. The small size of the differences in the average for median family income, median household income or average salary and wages raises the question whether any of these variables over this range provide a basis for distinguishing differences in the characteristics of program participants.
- The range of incomes included in the lowest (first) decile for Median Family Incomes, Median Household Incomes and Average Salary and Wages is quite wide, consistent with a wide range of family and household circumstances. For Median Family Income, the first decile includes all postcodes with median family incomes below $882/week, or, assuming that this value is consistent with annual median family income, an annual average value of just under $46,000. This range covers such widely different groups as recipients of the age pension through to households with one full time employed person – working in the retail industry, for example - earning up to 80 per cent of average weekly ordinary time earnings (AWOTE), as well as people in part time employment. The corresponding values for Median Household Income and Average Salary and Wages are $699/week (just over $36,000) and $30,550 respectively.
- Low income should not be conflated with socio-economic disadvantage. Median family income and median household income are weekly figures and may not be representative of family or household incomes over longer periods of time.

Similar analogies can be drawn for Figure 6.8 as well.

Figure 6.7 National penetration of solar PV by median family income, variation from average penetration, per cent of average

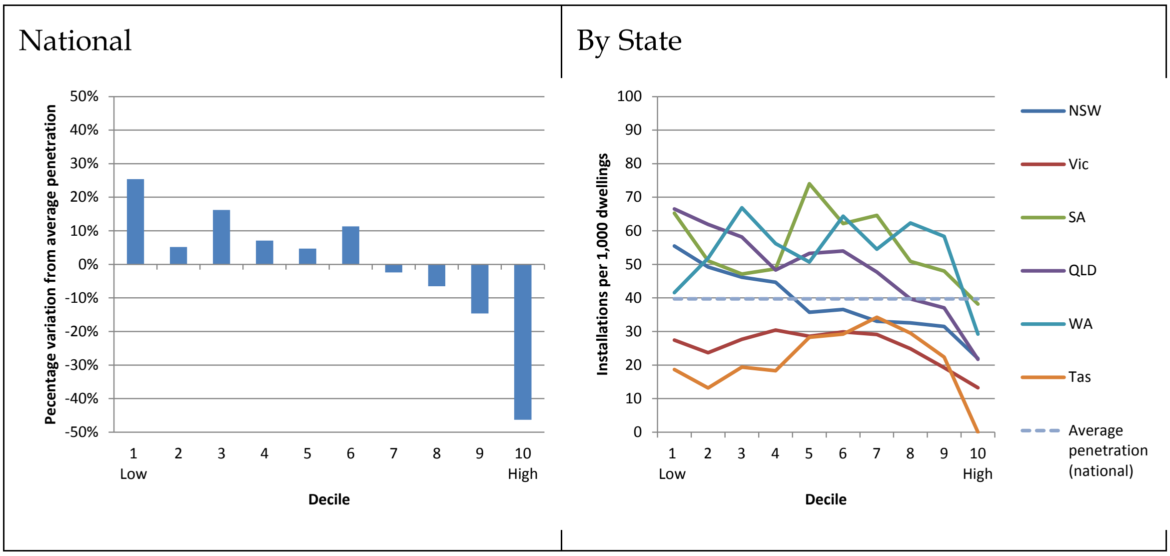
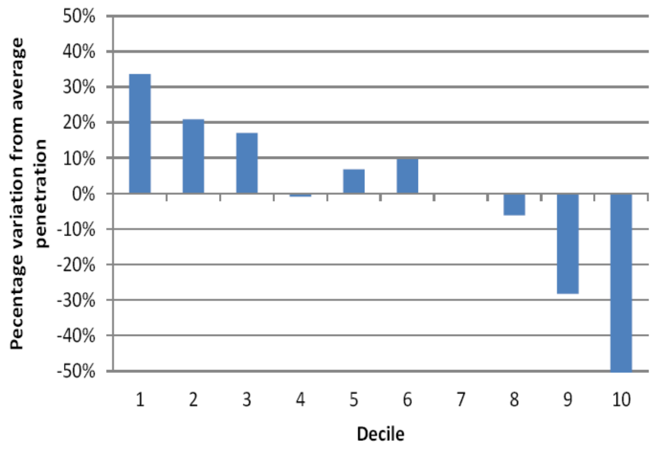


Figure 6.8 National penetration of solar hot water systems by median family income, variation from average penetration, per cent of average



6.4.3 Socio Economic Disadvantage and Advantage: Non-linear relationship with penetration

Seed Advisory's results for the ABS's 2006 Socio-Economic Indexes from Areas (the Index of Relative Social Advantage and Disadvantage (IRSAD), the Index of Economic Resources (IER) and the Index of Educational Opportunity (IEO)) suggest no strong linear relationships between these variables and uptake of solar PV or solar hot water systems. To the extent that a relationship exists between penetration and these indices, it appears to be non-linear.[40]

For Figure 6.9 and Figure 6.10, results show that:

- Consistent with the results for the income variables, penetration is relatively lower for the top two deciles for IRSAD and IEO. The most advantaged groups in the population, measured at the postcode level, have a significantly lower penetration of solar PV installations than the national average. For IER, the result for the highest (last) decile is statistically significant and in the opposite direction than the results for IRSAD and IEO.
- For deciles 2 to 7, penetration appears to be relatively higher than average for IRSAD and IEO and the difference is statistically significant in a number of deciles.
- In the lowest (first) decile, both the value for IRSAD and IER suggest that penetration is relatively lower than average at a statistically significant level, while the IEO value is not significantly different from the average.[41]

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40 ABS Cat No 2039.0, Information Paper: An Introduction to Socio-Economic Indexes for Areas (SEIFA), 2006 discusses the construction of the indexes and the variables included. IRSAD includes data on incomes, occupations, employment status, housing characteristics and access to broadband, while IER looks at income and housing characteristics and IEO looks at school leaving age and post school qualifications.

41 In the lowest decile, the IRSAD value for the postcodes included is below a score of 910. The ABS constructs IRSAD so that around 17.5 per cent of the population falls into postcodes with an IRSAD score of less than 900. Given the shape of the IRSAD distribution, this implies around 20 to 25 per

- The analysis suggests that, taking into account a broad range of characteristics of socio-economic disadvantage, penetration of small scale renewable energy technologies has been significantly lower in the lowest socio-economic decile than the national average.
- The analysis suggests that the finding relating to penetration and incomes between $250 and $649/week needs to be treated carefully and, in particular, should not be interpreted as implying that disadvantaged groups have benefited from the SRES at a higher rate than other groups.

Figure 6.9 National penetration of solar PV by Socio-Economic Indexes from Areas, variation from average penetration, per cent of average

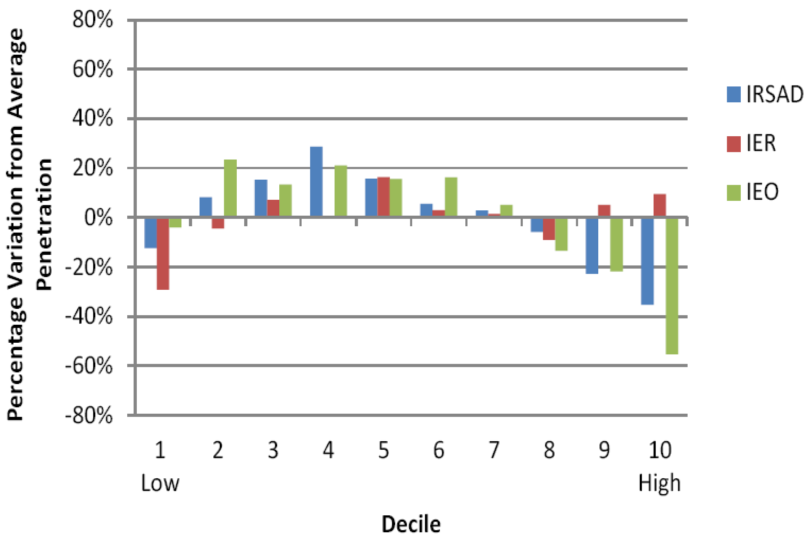
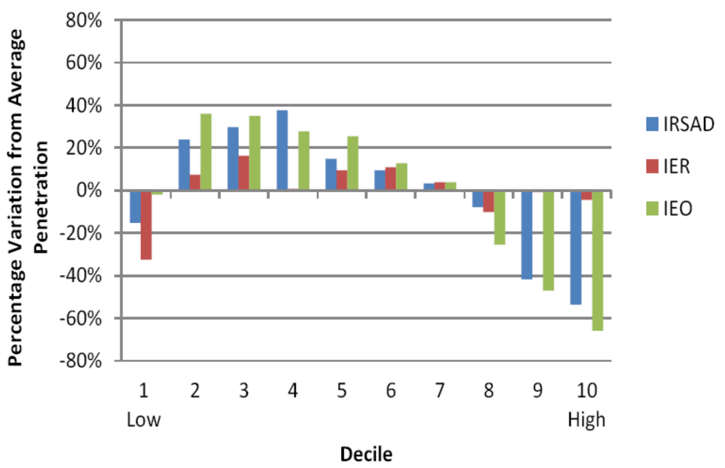


Figure 6.10 National penetration of solar hot water by Socio-Economic Indexes from Areas, variation from average penetration, per cent of average



cent of the lowest socio economic areas are included in the lowest decile in Seed Advisory's results, and suggests these groups are over-represented in the lowest decile of penetration of both solar PV and solar hot water systems.

6.4.4 Employment by industry sector and occupation: Positive relationship with penetration

Seed Advisory suggests that a large number of variables relating to industry of employment and a smaller number of variables relating to occupation are positively or strongly positively related to penetration of solar PV and solar hot water systems. Tempting as it is to interpret these results as meaning that in postcodes where a high proportion of construction industry workers live, the penetration of solar PV could be up to twice as high as the national average because of some innate characteristic of members of the construction industry, Seed Advisory believes that some part of these results is related to income.

The male AWOTE in the construction industry is relatively low, which may go some way to explaining Seed Advisory's results. AWOTE in the Financial and Insurance Services industry is relatively high, which is consistent with Seed Advisory's findings that the relationship between the share of Financial and Insurance Services industry employees in a postcode is negatively related to postcodes with high penetration. Other influences are clearly at work, however. For example, the relationship with the proportion of employees of the mining sector is likely to be related to density.

Results relating to occupations are more difficult to interpret. The proportion of technicians in the most likely (35 to 74 years) age range is strongly positive and might be hypothesized as being due to background and inclination. A similar relationship for the proportion of community workers in a postcode population is more difficult to explain.

6.4.5 Density: Negative relationship with penetration

Figure 6.11 and Figure 6.12 show the penetration per 1000 dwellings by postcodes ranked by the number of persons per square km of solar PV and solar hot water installations respectively.

Penetration increases over the first three deciles and then declines sharply. In the third decile penetration of solar PV installations is just over 150 per 1,000 dwellings, or nearly four times the national average. In contrast, installations in the densest deciles in Australia average around 15 per 1,000 dwellings, or a tenth of the penetration rate in the highest decile.

Higher density inner city suburbs show lower penetration than the outer suburbs, while the highest penetration per 1,000 dwellings can be found in a small number of areas in regional Victoria.

Figure 6.11 Penetration of solar PV by population density and postcode, persons per square km, installations per 1000 dwellings

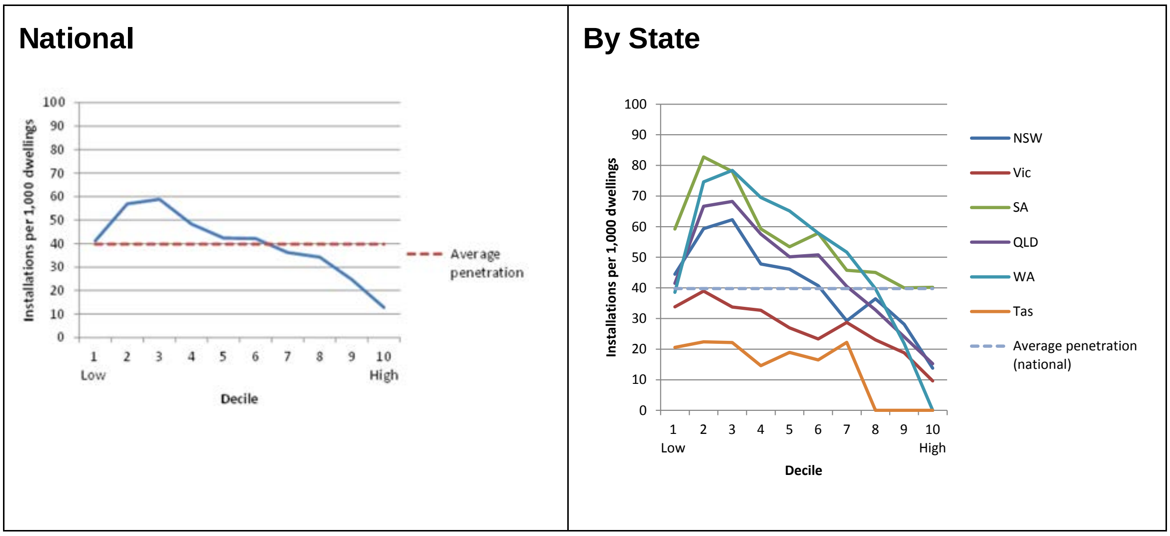
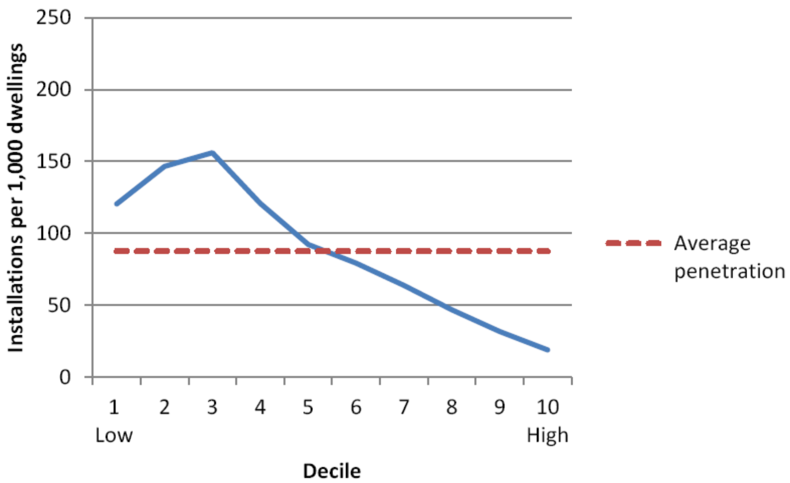


Figure 6.12 National penetration of solar hot water systems by population density and postcode, persons per square km, installations per 1000 dwellings



6.4.6 Housing type and other characteristics: Positive relationship with penetration

Nationally, the penetration of both solar PV and solar hot water systems is strongly positively related to the proportion of dwellings in a given postcode that are suitable – stand-alone or semi-detached – and owned or being purchased. A positive relationship exists between penetration for both technologies and the proportion of suitable dwellings. The analysis cannot distinguish whether ownership or dwelling characteristics is the key variable in this relationship, i.e. both make the cut-off point for significance.[42]

42 The strong positive classification refers to the slope of the relationship, rather than the explanatory value of the relationship. Looking purely at the R-squared for the two variables, it would suggest

Expanding the definition of suitable dwellings to include flats reduces the significance of the relationship to below Seed Advisory's cut-off point. Adding flats and caravans to the definition of suitable dwellings improves the R-squared, but not to a level consistent with Seed Advisory's cut-off point. We are aware of some industry commentary about penetration in caravan parks used for permanent occupancy, but this is a hypothesis which we have not tested.

Finally, penetration is higher in postcodes where the dwellings have a larger number of bedrooms. The lowest ten per cent of postcodes by penetration of solar PV have two or less bedrooms, while 80 per cent of solar PV installations are in postcodes where, on average, dwellings have between 2 and 2.7 bedrooms.

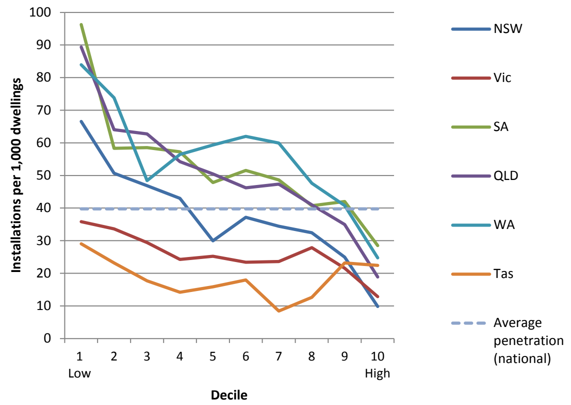
These are shown in Figure 6.11 and Figure 6.12.

6.4.7 Age: Negative relationship with penetration

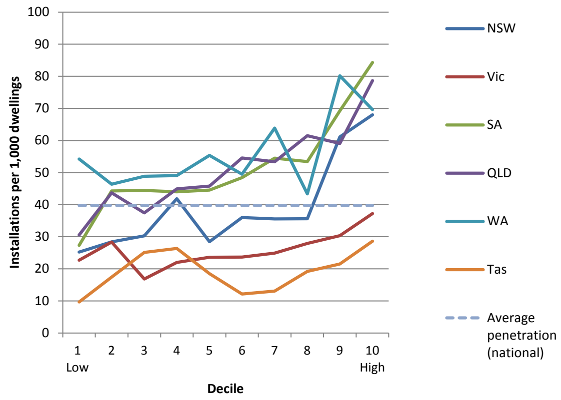
Nationally, the penetration of both solar PV and solar hot water systems is positively related to the proportion of the postcode population in the 35 to 74 years age range and strongly negatively related to the proportion of the population in the 20 to 34 years age range. This is shown in Figure 6.13.

Figure 6.13 Penetration of solar PV by proportion in relevant age range, installations per 1000 dwellings

Proportion of persons in younger age range (20 – 34)



Proportion of persons in expected age range (35 – 74)



At the state level, the penetration data for the proportion of the population in the young (20 to 34 years) age range displays significant variation. In all states, the relationship is negative, i.e. the higher the proportion of younger people, the lower the penetration rate. However, in Victoria and Tasmania, the results for all deciles are below the national average of 40 installations per 1,000 dwellings and significantly below the results for Western Australia, South Australia and Queensland.

that the relationship with dwelling type has greater explanatory value than that with dwelling type and occupancy status.

The analysis suggests no relationship between penetration and the proportion of the population in the 75 years plus age range.[43]

6.4.8 Solar hot water systems: new and replacement

For both new and replacement installations of solar hot water systems, penetration is lower in postcodes with higher density (a higher number of people per square kilometre). However, penetration varies with different variables when installations are characterised as new or replacement, suggesting two different dynamics may be at play:

- Postcodes with a high penetration of solar hot water on new buildings have one or more of the following: high proportions of families with young children; high proportions of separate or semi-detached dwellings that are owned or being purchased; higher average household sizes; higher numbers of bedrooms; and higher numbers of cars per dwelling.
- Postcodes with a high penetration of solar hot water systems replacing pre-existing systems have one or more of the following: higher proportions of the population in the 35 to 74 years age group; higher proportions of the population employed in the agricultural sector; and a higher proportion of Aboriginal and Torres Strait Islanders as a share of the population.

There are a number of relationships that appear to be common to both solar PV and solar hot water installations, including:

- the proportions of families with young children;
- the proportions of separate or semi-detached dwellings that are owned or being purchased;
- higher numbers of bedrooms; and
- higher numbers of cars per dwelling.

This suggests that characteristics of postcodes with a higher uptake of solar PV are similar to those with high penetrations of new solar hot water installations – by definition, areas with newer developments and younger families in outer urban areas. However, this group of characteristics has not been tested for explicitly.

6.5 Jurisdictional differences

The penetration of solar PV installations in NSW and Tasmania is discussed below to illustrate the differences between penetration levels and relationships at the state level.

6.5.1 NSW

Seed Advisory's analysis into the impact of the feed-in tariff scheme in NSW suggests that there was a significant increase in installations following the introduction of the

43 This is not consistent, however, with a conclusion that postcodes characterised by a higher proportion of people in the 75 years plus age group "do not care about the environment". Rather, the data supports a conclusion that old age is not a differentiating factor.

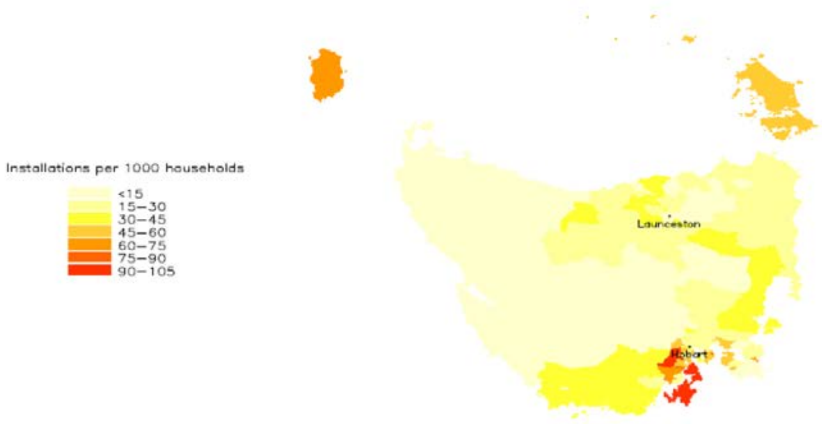
feed-in tariff scheme. Over the entire period, the NSW results differ from those for Australia as a whole in a number of areas, including:

- The absence of any relationship with the most likely age range, the proportion of young children, the proportion of children, and the average number of bedrooms per dwelling, all of which are significant on a national basis. Despite these differences, density (number of people per square km) has the same relationship with penetration in NSW as in Australia, i.e. the higher the density, the lower the penetration per 1,000 dwellings.[44]
- The strong positive relationship between solar PV penetration per 1,000 dwellings and Australian citizens as a proportion of the postcode population. Industry insights suggest that this may reflect access to finance, i.e. citizenship is a usual precondition to loans to finance the solar PV installation.

6.5.2 Tasmania

Results for solar PV penetration per 1,000 households for Tasmania suggest Tasmania exhibits markedly different characteristics to the rest of Australia. Penetration is highest in some of the suburbs of Hobart and on Bruny Island, but is, looking at Tasmania as a whole, significantly below the national average. This is shown in Figure 6.14.

Figure 6.14 Penetration of solar PV by Postcode, Tasmania, installations per 1,000 dwellings



A number of factors need to be taken into account, however, in interpreting the data:

- Lower penetration in Tasmania is a desired outcome of the policy that bases the STC multiple on zones that reflect the quality of the solar resources, where Tasmania is in the zone with the lowest multiple for STCs, meaning that, all other things being equal, payback in Tasmania would be slower than, for example, in Western Australia or NSW.

44 In the case of NSW, the results for density before and during the feed-in tariff are very interesting. Before the introduction of the feed-in tariff, a relationship exists, but it's flat – penetration doesn't vary with density, from decile to decile. Following the introduction of the feed-in tariff, density appears not to have a relationship with penetration, but over the data as a whole, density and penetration have the expected strong negative relationship displayed by the Australia wide data.

- Although Seed Advisory have found that, in general, using deciles determined by state averages resulted in relatively few differences compared with the Australia wide data, there are likely to be areas where Seed Advisory's approach conceals differences between the states. For example, to the extent that absolute incomes are lower in Tasmania than in other states or relative to the national average, using the national average may give rise to differences in the interpretation of the data.
- For example, the Tasmanian analysis suggests a positive relationship between median income and penetration rates for solar PV installations for deciles 1 to 9. No Tasmanian postcodes are included in decile 10 as no Tasmanian postcodes have a median income consistent with this national value. There are a number of other variables where Seed Advisory's approach does not adjust for state by state differences – share of the population employed in the mining sector, for example.

6.6 Further work

Seed Advisory has identified a number of areas where potential additional analysis could provide further useful insights. These include analysis on:

- comparisons between uptake by States and Territories;
- non-linear relationships and correlations;
- wealth and social advantage;
- comparing the results to findings on incidence and disadvantage;
- moving towards a predictive model; and
- a customer survey on social attitudes and program participation.

6.6.1 Comparisons between uptake by States and Territories

The data supplied by ORER covers a range of State-based additional incentives to encourage uptake of small scale renewable energy technologies. The differences and similarities in uptake from State to State could provide additional insight into the overall results.

In addition, at the individual State or Territory level, identifying the characteristics of areas with higher uptake may be helpful in future versions of the current programs or, as is required in the ACT, in the annual reset of the level of the feed-in tariff.

6.6.2 Non-linear relationships

The non-linear variables discussed in Seed Advisory's report have been based on a high level of judgment. Additional work to look at the significance of these variables and their interpretation, particularly in the areas of wealth and social advantage, could improve the ability to interpret and rely on the results.

Questions of causality in the data sets or correlations between the variables have not been examined. Exploring these relationships should add value to the analysis and future policy directions.

6.6.3 Wealth and social advantage

In the absence of a direct wealth variable at the postcode level, imputation credits were used, drawing on earlier work by BITRE.[45] Both BITRE's work and the Melbourne Institute's HILDA Survey indicate that the value of owner occupied housing is dominant in households' wealth portfolios in Australia. BITRE uses Australian Property Monitor's data on property values at the local government level to estimate house values. This data could be used and the results restated on a local government area basis to more directly explore the relationship between wealth and penetration of small scale renewable energy technologies.

This further work would also complement analysis previously done by AGL on feed-in tariff policies and whether it is an industry stimulus or regressive form of taxation.[46] In particular, AGL found that the policies were "significantly regressive in nature with the effective rate of taxation paid by low income households being almost three times higher than high income households".[47]

AGL's survey of 870 customers in NSW also indicated that 55% of solar PV customers have annual incomes of over $62,000, while 15% would have low incomes of less than $26,000.[48] The same customer base was surveyed on house price and it was found that 56% of the sample holds real property worth $600,000 or more.[49] AGL also found that there was a correlation between the weighted average cost per household and household income, and that the implied rate of taxation was inversely correlated with income, which is a regressive form of indirect taxation.[50]

6.6.4 Comparing the results to findings on incidence and disadvantage

Seed Advisory's results provide no insight into the incidence of the costs of the Federal and state schemes to electricity consumers. However, IPART has identified a number of local government areas where the incidence of the costs of the schemes is likely to particularly disadvantage consumers. To compare penetration and the characteristics of the disadvantaged areas, the results would need to be recalibrated to local government areas consistent with IPART's data and compared with IPART's findings on the characteristics of customers in these areas.[51]

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45 BITRE's results were based on local government areas, but for the purposes of Seed Advisory's analysis, it was assumed that the relationship between wealth and imputation credits received was consistent at a postcode level.

46 Tim Nelson, Paul Simshauser and Simon Kelley, 'Australian Residential Solar Feed-in Tariffs: Industry Stimulus or Regressive Form of Taxation?' (Working Paper No 25, AGL Applied Economic and Policy Research, March 2011).

47 Ibid 14.

48 Ibid 10. Note: dollar values are assumed to be expressed in 2010 dollars.

49 Ibid 11.

50 Ibid 11.

51 Seed Advisory could not provide any insight into the incidence of the costs of the various schemes to consumers because there was no information on energy consumption. The Census data and other publicly available data do not provide a detailed small area breakdown of household energy consumption that could be used to supplement Seed Advisory's existing results. IPART's survey data, from which their results are drawn, includes energy consumption by household.

6.6.5 Moving towards a predictive model

In other similar work in other industries, predictive models with strong explanatory performance have been built using a similar process to that used in the truncated multivariate analysis. In pursuing this objective, which Seed Advisory believes could be significant in evaluating the statistical models of penetration being built for the AEMC. A process of testing and retesting the data set would allow the data set to be narrowed and provide for a predictive model to be developed for small scale renewable technology penetration to supplement the insights from other models of potential uptake.

6.6.6 Customer survey on social attitudes and program participation

In discussing the results of the occupational variables (e.g. the behaviour of community sector workers), Seed Advisory believes the publicly available data sets at the postcode or small area level may be insufficient to understand the behaviour identified.

Desirably, the public domain data would be supplemented with a customer survey on social attitudes from people who have participated in the various Federal and state programs and from a control group who have not participated. In order to do this, whatever data source is used to identify program participants (e.g. ORER's data, data from the relevant state or territory regulator, or data from the retailers administering the feed-in tariff programs), participants' consent to being contacted would be required. With that consent, modern polling techniques would allow an appropriately structured survey of attitudes to be undertaken within a relatively short period of time, supplementing our understanding of the different uptake of the available programs across groups in the community. A customer survey of this kind could assist to further inform our initial analysis.

6.7 Summary

The following are key points from Seed Advisory's analysis:

- There has been little analysis undertaken on the groups of energy consumers that are benefiting from the SRES and those that are not. Seed Advisory combines ORER's national REC data with a range of demographic data. Previous published studies have been narrow in their scope on specific relationship types.
- The penetration of the SRES uptake is higher in postcodes where the share of the population falling in the 35-74 years age group is higher, a higher share of detached and semi-detached houses that are owned or being purchased, a larger number of bedrooms, a higher proportion of dwellings with young children, a higher number of cars per household, relatively low density, or a higher proportion of the population with an income in the range between $1,000 to $1,700/week.
- Penetration rates of the SRES uptake are lower for the lowest decile socio-economic groups who may not have benefited from existing incentives to install small scale renewable energy technology. Also, penetration rates may be lower in postcodes where the share of the population falling in the 20 to 34 years age

group is higher, a higher share of people with poor English, or the proportion of family or households with weekly gross income is $1,700 and above.[52]

- Analysis into the impact of the FiT scheme in NSW suggests that there was a significant increase in installations following the introduction of the FiT scheme. Over the entire period, the NSW results differ from those for Australia as a whole in a number of areas, including the absence of any relationship with the most likely age range, the proportion of young children, the proportion of children, the average number of bedrooms per dwelling, and the strong positive relationship between solar PV penetration per 1,000 dwellings and Australian citizens as a proportion of the postcode population.
- Results for solar PV penetration per 1,000 households for Tasmania suggest Tasmania is different. Penetration is highest in some of the suburbs of Hobart and on Bruny Island, but is, looking at Tasmania as a whole, significantly below the national average.
- A number of areas for further work has been identified that can better identify and understand the characteristics of customers taking up these technologies to assist policy makers in refining and better targeting renewable energy technology initiatives. These include analysis on comparisons between uptake by States and Territories, non-linear relationships, wealth and social advantage, comparing the results to findings on incidence and disadvantage, moving towards a predictive model, and social attitudes and program participation.

52 Values are in 2006 dollars.

7 Conclusions

From our analysis to date we can draw a number of conclusions about the impact of the enhanced RET. We are also suggesting some further analysis that could be undertaken. Our initial conclusions are:

- Under policy settings as at late June 2011 there is a significant risk that the enhanced RET target will not be met by 2020, without a price on carbon emissions.
- The LRET is forecast to suppress wholesale prices, which reduces the profitability of peaking gas fired generators. This may lead to a risk that the target for unserved energy in the NEM may not be met in a number of States over a number of years.
- There is a risk that consumers may not receive the benefit of lower wholesale prices, as the LRET creates a divide between wholesale prices and the retail prices paid by consumers. In addition, the compliance costs for customers of the LRET will be high because LGCs will trade at or close to the penalty price for a material proportion of the scheme's life due to the forecast shortfall in the LRET.
- Although the direct costs of the SRES for customers are expected to fall considerably in the coming years, there will be a substantial legacy cost for customers as a result of the already committed cost of jurisdictional FiT schemes.
- The relative abatement cost of the LRET is substantially lower than the SRES, suggesting it offers much better value for money.
- There are likely to be some increased costs for additional ancillary services requirements. While these costs are not large in the context of the overall costs of the enhanced RET, it may be appropriate to consider options to better target and mitigate these costs.

The Commonwealth Government has committed to a review of the enhanced RET policy next year. We consider that our analysis to date identifies a number of issues that would merit consideration in that review, including:

- The design of the SRES – Its current design and uncapped nature means that it is very difficult to forecast its impact and costs. This has led to a number of changes to the policy settings, undermined the achievement of the LRET target and led to unexpected price increases for energy consumers.
- The aim of the LRET – Our forecasts suggest it is unlikely that the target for the LRET will be met without a carbon emissions price.[53] Increasing the penalty price would allow more renewable generation to be profitable, but would increase costs for consumers, further reduce wholesale prices, and may lead to higher levels of unserved energy.
- The design of jurisdictional FiT schemes – There is currently no common framework for setting FiTs. We believe there would be merit in the MCE developing a common framework for setting FiT schemes based around the costs

[53] We have assumed a profile of carbon emissions prices based on those considered by Commonwealth Treasury under the proposed Carbon Pollution Reduction Scheme.

avoided by installing solar PV, while the setting of the tariff rate and cap for the scheme could remain a jurisdictional responsibility.

- The beneficiaries of the SRES – It is not clear whether the Commonwealth Government had a particular view or intention about which types of consumers would benefit from the SRES, and which types of consumers would fund the SRES. Our initial analysis suggests that certain groups of consumers are benefiting much more than others.

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A Summary of the enhanced RET and jurisdictional initiatives on SRES

This appendix provides a summary of the national and jurisdictional schemes related to consumer installation of renewable energy technology. This covers the enhanced RET (including the Solar Credits Multiplier), feed-in tariff schemes, and solar hot water rebates.

A.1 The enhanced RET

The expanded RET was established by the Commonwealth Government in August 2009 to encourage additional renewable energy generation to meet the Commonwealth's commitment to achieving a 20% share of renewables in Australia's electricity supply by 2020. The expanded RET commenced on 1 January 2010 and served to expand the previous Mandatory Renewable Energy Target (MRET) by more than four times from 9,500 GWh to 45,000 GWh.

On 1 January 2011, the expanded RET was split into two parts: the SRES and LRET. The SRES is used to support households, small business and community groups with installation of eligible renewable energy systems. The schemes are aimed to encourage additional generation of electricity from renewable energy sources from small-scale systems and renewable energy power stations. The schemes are administered by ORER.

After 30 June 2012 and subsequently every two years, a review of the operation of renewable energy legislation must be undertaken as soon as practicable. This would include:[54]

- the operation of the LRET and SRES;[55]
- the operation of the eligibility criteria for renewable energy sources, accreditation of power stations, eligibility requirements for solar water heaters and small generation units;[56]
- the operation of the large-scale generation shortfall charge of $65 per MWh;[57]
- the operation of the small-scale technology shortfall charge of $65 per MWh;[58] and
- the diversity of renewable energy access to the LRET and SRES, with reference to a cost benefit analysis of the environmental and economic impact of that access.[59].

The above review may have an impact on the existing arrangements for the enhanced RET.

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54 *Renewable Energy (Electricity) Act 2000* (Cth) s162.

55 *Renewable Energy (Electricity) Act 2000* (Cth).

56 *Renewable Energy (Electricity) Regulations 2001* (Cth).

57 *Renewable Energy (Electricity) (Large-scale Generation Shortfall Charge) Act 2000* (Cth).

58 *Renewable Energy (Electricity) (Small-scale Technology Shortfall Charge) Act 2010* (Cth).

59 *Renewable Energy (Electricity) Act 2000* (Cth).

A.1.1 SRES

The SRES creates a financial incentive for households, small businesses and community groups that install eligible small scale renewable energy systems, such as solar panels, small wind turbines, micro hydroelectric systems, solar water heaters, and heat hump water heaters. Under the SRES, these owners are entitled to STCs which can be sold to buyers (liable entities) such as wholesale electricity retailers and some generators.

An STC is generally equivalent to:

- 1 MWh of renewable electricity deemed to be generated by small generation units (unless the Solar Credits REC multiplier applies); or
- 1 MWh of electricity deemed to be displaced by the installation of solar water heaters.

Owners of STCs have two options for gaining a financial benefit for their certificates: (1) exchange a financial benefit through a registered agent; or (2) sell the financial benefit through the open STC market or through the online STC Clearing House. Through the online STC Clearing House option, the financial benefit is guaranteed to be $40 (excl GST).

Unlike the LRET, there is no cap on the number of STCs that can be created. However, SRES has an implicit target of 4000 GWh. ORER estimates on an annual basis the number of STCs that may be created and advises the Minister. Based on an estimate for the number of STCs needed to be acquired by liable entities, the Minister then determines the Small-scale Technology Percentage (STP) by 31 March each calendar year. The STP indicates the number of certificates liable entities must purchase each year. The STP for:

- 2011 is 14.8% (equivalent to 28 million STCs as a proportion of total estimated electricity consumption for the 2011 year);
- 2012 is 20.87% (equivalent to 38.5 million STCs as a proportion of total estimated liable electricity for the 2012 year); and
- 2013 is 6.25% (equivalent to 12.1 million STCs as a proportion of total estimated liable electricity for the 2013 year).[60]

Liable entities can surrender these STCs to ORER on a quarterly basis to demonstrate compliance, or throughout the year either for non-compliance reasons or voluntarily for any reason.

The price of STC may be reviewed by the Minister. The Minister may reduce the $40 price prospectively by legislative instrument should this be considered appropriate.

In addition to the date and size of the installation, the number of STCs will be determined by the geographic location. ORER uses four zones made up of Australian postcodes which are based on climate and solar radiation levels. The more sunlight available in a zone means that the number of STCs issued to the owner increases. For solar PVs, this is further increased under the Solar Credits Multiplier.

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60 STPs for 2012 and 2013 are currently non-binding, and will be determined by 31 March 2012 and 31 March 2013 respectively.

A.1.2 LRET

The LRET creates a financial incentive for large-scale renewable power stations like wind farms, commercial solar and geothermal. Under the LRET, these owners are entitled to LGCs which can be sold to buyers (liable entities) such as such as wholesale electricity retailers and some generators.

An LGC is generally equivalent to 1 MWh of eligible renewable electricity generated above the power station baseline. LGCs are created by the renewable energy power station generating electricity above the baseline. This baseline is determined by ORER as part of the accreditation process for the power station.[61]

The ORER is responsible for validating the LGC. The LGC can then be transferred between the renewable power station and liable parties for a negotiated price, where payment is done outside the REC Registry but LGCs are transferred inside the REC Registry.

Unlike the SRES, there is a cap on the number of LGCs that can be created. These are based on legislative annual energy targets in GWh.[62] The renewable energy targets must be achieved over the period 2001 to 2030. The annual LRET target for:

- 2011 is 10,600 GWh;[63]
- 2012 is 16,338 GWh; and
- 2013 is 18,238 GWh.

With the exception of 2013 and 2014, the annual LRET target will increase each year until 2020 onwards where the annual target will be 41,000 GWh.

The Renewable Power Percentage (RPP) sets the amount of certificates liable entities must purchase each year. The RPP for 2011 is 5.6% of each retailer's load (equivalent to 10.6 million LGCs as a proportion of total estimated electricity consumption for the 2011 year).

Liable entities can surrender these LGCs on an annual basis to demonstrate compliance, or throughout the year either for non-compliance reasons or voluntarily for any reason. If liable entities fail to surrender these LGCs, then they will face a shortfall charge of $65 per MWh.

A.2 Solar Credits Multiplier

The Solar Credits Multiplier is a mechanism inside the enhanced RET scheme to provide further support to the households, businesses and community groups that install solar panels, wind and hydro electricity systems by multiplying the number of STCs created by these systems. For example, it currently provides three times as many STCs to those installing small-scale rooftop solar photo-voltaic (PV) systems.

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61 The baseline is generally the average amount of electricity generated over the 1994,1995 and 1996 years. Power stations which generated electricity for the first time after 1 January 1997 have a baseline of zero.

62 *Renewable Energy (Electricity) Act 2000* (Cth) s40.

63 The legislated 2011 target of 10,400 GWh was adjusted by ORER to 10,600 GWh by the total actual RECs received compared to the 2001 to 2009 cumulative targets.

To be eligible to apply for solar credits, the system must be an eligible 'small generation unit' i.e. a solar PV system with a capacity of up to 100 kW, a small wind turbine with a capacity of up to 10kW, or a micro-system with a capacity of up to 6.4 kW.

From 29 June 2010, solar credits also applied to the first 1.5 kW of capacity installed for systems connected to a main electricity grid and up to the first 20 kW of capacity for off-grid systems.

The support from solar credits will still be in place until 1 July 2013, but subject to some adjustment to the multiplier. For systems installed between 9 June 2009 to 30 June 2011, the multiplier is five. For systems installed between 1 July 2011 to 30 June 2012, the multiplier is reduced to three and will reduce by one at each subsequent financial year until 30 June 2013. From 1 July 2013 onwards, a standard rate of certificate creation (i.e. a multiplier of one) will apply for systems installed from this date.

The multiplier has been changed in December 2010 and May 2011. In December 2011, the reduction in the multiplier was brought forward by one year from five to four (which would take effect from 1 July 2011 until 30 June 2012, and reduce by one at each subsequent financial year until 30 June 2013). The reason this was done to reflect the significant reductions in solar PV installation costs as a result from a strong economy, a high dollar and falling technology costs.[64] In May 2011, the reason that the multiplier was changed from four to three was because of strong demand for solar PVs, with declining system costs, a strong Australian dollar and economy, and incentives from Solar Credits and jurisdictional feed-in tariff schemes. [65] The changes will take effect from 1 July 2011 until 30 June 2012, and the multiplier will reduce by one at each subsequent financial year until 30 June 2013.

A.3 Renewable Energy Bonus Scheme - Solar Hot Water Rebate

In July 2009 the Council of Australian Governments agreed to phase-out the use of electric resistance water heaters as part of the National Partnership Agreement on Energy Efficiency. Implementation of this measure has been progressed by the MCE under the broader National Framework for Energy Efficiency. Implementation of this agreement varies between jurisdictions but broadly involves the banning of the use of electric resistance water heaters in new-build detached or semi-detached dwellings where natural gas is available from 1 January 2010.

The national Renewable Energy Bonus Scheme (REBS) provides rebates to support the installation of solar hot water systems and heat pump water heater systems. The REBS solar hot water rebate allows eligible households to claim a rebate of $1,000 for a solar hot water system or $600 for a heat pump water heater. To be eligible, the new system has to replace an existing electric storage hot water system, be eligible for at least 20 STCs at the time of purchase, and be purchased and installed from 20 February 2010 until a date to be notified by the Commonwealth Government.

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64 Minister for Climate Change and Energy Efficiency, Media Release, 'Solar Credits amendments', 1 December 2010.

65 Minister for Climate Change and Energy Efficiency, Media Release, 'Solar credits changes to ease electricity prices', 5 May 2011.

A.4 Jurisdictional renewable energy schemes

In addition to the Commonwealth enhanced RET and Renewable Energy Bonus Scheme, a number of jurisdictions also have their own renewable energy schemes. These schemes provide additional incentives for the installation of small-scale renewable technologies in each jurisdiction.

A.4.1 Australian Capital Territory

Feed-in tariff scheme

The government of the ACT adopted a feed-in tariff scheme and gave effect to that decision through the *Electricity Feed-in (Renewable Energy Premium) Act 2008* (Cth). The Act came into effect on 1 March 2009 and requires electricity distributors to connect generators of renewable energy to the electricity network and to reimburse those generators' electricity suppliers (retailers) for the difference between the premium rate determined for renewable electricity and the normal cost of electricity. The retailer is then required to pay the generator the premium rate.

This scheme is gross-based under which the occupiers are to be paid for each unit of electricity that is generated. It rewards households and businesses (except non-educational government agencies) that install renewable energy generation technology by paying a premium price for the electricity they generate. Payments are made for 20 years in the ACT.

In September 2010, the ACT Government released details of a proposed expansion of its feed-in tariff scheme that may incorporate medium and large-scale generators, with capacity of up to 200 kW and beyond.[66]

The ACT Government agreed to establish an expanded feed-in tariff scheme with the following elements:

- an overall scheme cap of 240 MW of generating capacity;
- large scale generation category for generators larger than 200 kW (category cap of 210 MW);
- medium scale generation category for generators between 30kW and 200 kW (category cap of 15 MW); and
- existing micro generation category (household rooftop) up to 30 kW (category cap of 15 MW).

This was implemented in two stages:

1. medium scale generation suitable for larger areas such as shopping centres, warehouses and large office buildings will be supported through amendments to the existing *Electricity Feed-In (Renewable Energy Premium) Act 2008* (ACT);[67] and

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66 Minister for the Environment, Climate Change and Water, Media Release, 'Labor delivers on making Canberra Australia's Solar Capital', 13 September 2010.

67 The *Electricity Feed-in (Renewable Energy Premium) Amendment Bill 2010* (ACT) was passed on 17 February 2011 and commenced on 24 February 2011.

2. the introduction of separate legislation for large scale generation with provision of premium payments to be allocated through an auction process. The ACT Government will make 40 MW available to auction as the first tranche of the large scale generation category.

From 1 March 2009 until 30 June 2010, the premium price was to be 50.05 ¢/kWh for systems up to 10 kW. For systems between 10kW and 30 kW, a rate of 40.04 ¢/kWh (excluding GST) will be paid. 45.7 ¢/kWh is being paid for all systems up to a 30 kW capacity installed from 1 July 2010 to 30 June 2011. In April 2011, the ACT Government announced that the same rate of 45.7 ¢/kWh would remain from 1 July 2011 to 30 June 2012.[68] This was to take into account the possibility of a reduction in the strength of the Australian dollar internationally and the impact that would have on the price of solar technology. The ACT Government noted that a further review of the premium rate could occur should further information emerge that significantly changes the factors that apply to the ACT scheme.

From 31 May 2011, the micro generation category was closed to any new applications as the legislated cap had been reached.[69] The ACT Government considered that the scheme had delivered more than was expected, and the rapid increase in uptake was driven by large reductions to Commonwealth rebates from 1 July2011.

On 12 July 2011, the ACT's medium scale generation category was opened to small scale- installations. On 14 July 2011, the Chief Minister announced the closure of the medium scale generation feed in tariff scheme as the cap of 15 MW had been reached.

Solar hot water rebate

The ACT Government provides a $500 rebate for expenditure of $2,000 or more on the priority recommendations in the Home Energy Advice Team (HEAT) Audit report. This includes replacement of an electrical hot water service with a solar hot water service.

A.4.2 New South Wales

Feed-in tariff scheme

In November 2009, the NSW Government announced the introduction of feed in tariff scheme, also known as the Solar Bonus Scheme, in which the following aspects are addressed:

- a gross feed-in rate of 60 ¢/kWh;
- eligibility under the scheme is for small customers (households and small businesses consuming less than 160 MWh of electricity each year) who produce renewable energy through solar PV systems and wind turbines connected to the grid and up to 10 kW in capacity;

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68 Minister for the Environment, Climate Change and Water, Media Release, 'Feed-in tariff to remain unchanged', 1 April 2011.

69 Minister for the Environment and Sustainable Development, Media Release, 'Micro Scale Feed-in Tariff Closes', 1 June 2011.

- the maximum amount an individual generator could receive in one year is $10,000; and
- a seven-year duration, beginning on 1 January 2010 and concluding on 31 December 2016.

A statutory review of the NSW Solar Bonus Scheme was undertaken in accordance with legislation when it reached 50 MW of installed capacity in mid-2010. The review showed that by 27 October 2010, the scheme had created more than 100 MW of renewable energy capacity and more than 50,000 customers had joined the scheme. On 27 October 2010, the NSW Government announced a major revamp of the scheme that:

- immediately closed the current program from midnight 27 October 2010;
- reduced the tariff rate from 60 ¢/kWh to 20 ¢/kWh; and
- introduced an overall capacity limit of 300 MW for all generators connected under the scheme.[70]

The new program was to be subject to a review on 1 July 2012 and at the end of the program on 31 December 2016.

From midnight 28 April 2011, the NSW Government placed on hold applications to the Solar Bonus Scheme, subject to the outcomes of the Solar Summit. This was because the NSW Government wanted to limit electricity price rises as a result of the Solar Bonus Scheme.[71] The NSW Government held its first Solar Summit on 6 May 2011 which developed how the Solar Bonus Scheme's costs would be managed and ensure further development of solar energy in NSW. On 13 May 2011, the NSW Government announced the closure of the Solar Bonus Scheme to new applicants effective midnight 28 April 2011. The NSW Government also announced planned changes to the NSW Solar Bonus Scheme which would have included abolishing the 300 MW connected capacity limit, and reducing the feed-in tariff rate for customers already receiving or who applied for the 60 ¢/kWh to 40 ¢/kWh rate from 1 July 2011 for the remainder of the Scheme.[72] The reason the NSW Government planned to make these changes was to reduce the burden of the Scheme on NSW taxpayers, especially on households not participating in the Scheme.

However, on 7 June 2011, the NSW Government decided not to proceed with the planned changes because of concerns raised by consumers who entered the Scheme in good faith and to give them certainty, although the NSW Government noted that the Scheme will impose a burden on NSW families.[73]

Solar hot water rebate

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70 NSW Government, News Release, 'NSW Government Revamps Solar Bonus Scheme', 27 October 2010.

71 NSW Government, Media Release, 'NSW Government places hold on Solar Bonus Scheme', 29 April 2011.

72 NSW Government, Media Release, 'NSW Government announces closure of Solar Bonus Scheme', 13 May 2011.

73 NSW Government, Media Release, 'Solar Bonus Scheme', 7 June 2011.

New South Wales have incorporated changes within its respective building codes effectively banning electric water heaters in new buildings from 1 January 2010.

In addition to the national REBS, the NSW Government offers a rebate of $300 for five star, solar or heat pump hot water system installed when replacing an existing electric hot water system. This is limited to $1500 worth of rebates per property. Other eligibility requirements for this rebate include that the system must have been purchased and installed between 1 October 2007 and 30 June 2011, not be used for non-domestic purposes, and be a new system that is eligible for 20 STCs.

A.4.3 Northern Territory

Feed-in tariff scheme

There is currently no feed-in tariff scheme offered by the Northern Territory Government. However, feed-in tariffs are provided by the Power and Water Corporation and Alice Springs. As part of Alice Solar City initiative under the Australian Government's Solar City program, Alice Springs residents can receive a gross feed-in tariff rate of 51.28 ¢/kWh, which is capped at $5 per day. For other parts of NT, Power Water Corporation provides domestic customers a gross feed-in tariff of 19.23 ¢/kWh.

Solar hot water rebate

The Northern Territory Government offers a Solar Hot Water Retrofit Rebate, administered by the Power and Water Corporation. The rebate is available to eligible pre-existing homes to replace electric systems with solar hot water systems. The rebate is designed to compensate for additional plumbing and roof structure upgrades that may be required to complete the installation.

Households built in 2000 or before this time with timber trusses in their roofs, requiring reinforcement in order to support the new solar hot water system, will receive a rebate of up to $1000. Households built in 2000 or before that have steel trusses in their roofs, requiring only additional plumbing, will receive a rebate of up to $400.

A.4.4 Queensland

Feed-in tariff scheme

The Queensland Government Solar Bonus Scheme commenced on 1 July 2008. The Solar Bonus Scheme pays eligible households and other small customers for the surplus electricity generated from solar PV panel systems, which is exported to the Queensland electricity grid.

The scheme is gross-based, which rewards customers whenever they generate more electricity than they are using – not just the balance at the end of the quarter, but whenever generation exceeds consumption during the day.

Some of the key aspects of the scheme are listed below:

- the scheme is available to small electricity customers who consume less than 100 MWh of electricity a year;

- customers will be paid 44 ¢/kWh for surplus electricity fed into the grid;
- solar PV systems with a capacity of up to 10 kVA for single phase power and 30 kVA for three-phase power.

It is legislated under the *Electricity Act 1994* (NSW) that the solar bonus of 44 ¢/kWh will expire in 2028. The Scheme will be reviewed in 2018 or when 8MW is installed.

On 10 May 2011, the Queensland Government reported that there was 149 MW of installed residential solar PV capacity in Queensland, with more than 72000 participants.[74] The solar bonus will be retained at its current rate of 44 ¢/kWh. However, the size of eligible individual solar PV systems will be limited to 5kW capacity and to one system per premises. This cap on the size and number of new systems eligible for the solar bonus was changed because of the growing numbers of people investing in large scale solar PV systems up to 30kW, which has lead to higher than expected costs for Queensland consumers. This change in the eligibility criteria will commence from 7 June 2011.

Solar hot water rebate

Queensland have made additional changes to its respective building codes, such that the effective ban applies to electric water heaters in new buildings and to replacement water heaters in 'class 1' dwellings (i.e. detached or semi-detached dwellings) where reticulated natural gas is available.

In addition to the national REBs, the Queensland Government offers a rebate to eligible households that replace their electric storage hot water system with a solar hot water system or heat pump. Pensioners and low income earners receive a $1000 rebate, while others will receive a $600 rebate. Additional eligibility requirements for the $600 rebate include that these new systems must be purchased from 13 April 2010 and be eligible for at least 20 STCs. The purpose of the rebate is to ensure Queenslanders purchase quality systems that are approved by ORER, and systems are installed by suitably licensed contractors, plumbers and gas fitters, and electricians.

A.4.5 South Australia

Feed-in tariff scheme

From 1 July 2008, South Australian small customers were able to receive a premium guaranteed tariff of 44 ¢/kWh for unused solar electricity into the grid. To be eligible for the scheme, customers must consume less than 160 MWh of electricity per annum and have installed a solar PV electricity system. This scheme was closed on 1 October 2011.

A transitional 16c/kWh feed in tariff scheme commenced on 1 October 2011. This scheme was legislated following the refusal of the South Australian Parliament in June 2011 to pass proposed amendments by the South Australian Government to increase its feed in tariff from 44c/kWh to 54 c/kWh.

74 Queensland Government, Ministerial Media Statement, 'Queensland Solar Bonus Scheme delivers savings and jobs', 10 May 2011.

Solar hot water rebate

South Australia have made additional changes to its respective building codes, such that the effective ban applies to electric water heaters in new buildings and to replacement water heaters in 'class 1' dwellings (i.e. detached or semi-detached dwellings) where reticulated natural gas is available.

The Solar Hot Water Rebate Scheme in South Australia is only available to concession card holders who install a new solar water heater or electric heat pump water heater. Under this scheme, customers receive a $500 rebate. The types of hot water system installed that would be eligible for the rebate will depend on whether it is a new home, an additional water heater installation, replacement of an existing water heater, the availability of natural gas or LPG in the street, and type of water heater being replaced. The water heater must also be eligible for a minimum of 18 STCs.

A.4.6 Tasmania

Feed-in tariff scheme

In Tasmania, there is no legislated feed-in tariff, although there have been moves to introduce a gross feed-in tariff in the State soon. However, Aurora Energy offers a Net Metering Buyback Scheme for residential customers who install a renewable grid-connected energy system larger than 3kW. These customers receive with receive a net feed-in tariff rate of 22.648 ¢/kWh.

Solar hot water rebate

Tasmania is not implementing any changes with respect to electric resistance water heaters in new buildings due to the low greenhouse-intensity of its local electricity supply.

A.4.7 Victoria

Feed-in tariff scheme

The Victorian feed-in tariff for solar power systems commenced in November 2009. There are two feed-in tariff schemes in Victoria: a premium feed-in tariff scheme; and a standard feed-in tariff scheme.

Under the program, Victorian households, community organisations, or small businesses with small-scale solar PV systems of up to 5 kW capacity and consumption of less than 100 MWh per year (for a small business or community organisation) are eligible for the premium feed-in tariff. This means they will receive a guaranteed minimum credit of at least 60 ¢/kWh of unused power fed back into the state electricity grid. Victorian electricity retailers with more than 5000 customers must offer this tariff. This scheme is a net feed in tariff that will run for 15 years. The total cap across Victoria for the scheme is 100 MW.

The Victorian premium feed in tariff will be closing to new applicants soon. To be considered for the premium rate, customers must have installed their solar panels, lodged specific paperwork with their electricity distributor and retailer, and have agreed to a premium feed in tariff contract with their retailer by 30 September 2011. A transitional feed in tariff of 25 c/kWh will commence on 1 January 2012 and will have a capacity cap of 75 MW. The transitional feed in tariff will provide for credits for eligible systems until 31 December 2016.

Victorian households, community organisations and small businesses generating electricity from wind, solar, hydro and biomass sources with more than 5 kW but less than 100 kW capacity are eligible for the standard feed-in tariff. This allows customers to receive a "one-for-one" payment rate for any excess electricity fed back into the state electricity gird. Victorian electricity retailers with more than 5000 customers must offer this tariff. There is no end-date for this scheme.

Solar hot water rebate

Victoria have incorporated changes within its respective building codes effectively banning electric water heaters in new buildings from 1 January 2010.

In addition to the national REBS, there are five solar hot water system rebates in Victoria:

- a solar hot water system installation rebate for metropolitan Melbourne;
- a solar hot water system installation rebate for regional Victoria;
- a Victorian Energy Saver Incentive (Victorian Energy Efficiency Target (VEET));
- a gas hot water rebate for replacement of peak (day rate) electric water heaters; and
- benefits for bushfire communities amongst solar hot water adjustments.

The first two rebates encourage households to install solar hot water systems by providing rebates between $300 - $1500 for metropolitan Melbourne and between $400 - $1600 for regional Victoria. Rebates vary depending on the amount of water produced, solar contribution and relative cost of installation of the solar hot water systems. To be eligible for the solar hot water system installation rebates, the installation may be:

- a replacement of natural gas or LPG water heater with a gas-boosted solar system;
- an addition of a solar water heater to an existing natural gas or LPG water heater by installing as a preheater;
- an addition of solar panels to an existing off-peak electric water heater by installing a retrofit kit;
- a replacement of an existing solar, wood, briquette or oil-fuelled water heater with gas-boosted or electric solar system. It must be natural gas-boosted if available in the street. Existing LPG-boosted solar water heaters can only be replaced with gas-boosted systems; or
- a replacement of an electric water heater with gas-boosted or electric-boosted solar system (if natural gas is not available in the street) where the applicant has

installed ceiling insulation under the Australian Government's Homeowner Insulation Program.[75]

The VEET scheme was introduced on 1 January 2009 and provides incentives to promote the uptake of household energy efficient technology. The Victorian Energy Efficiency Certificates (VEECs) are created when customers replace their current hot water system for a solar hot water system. Liable entities such as large electricity and gas retailers have to buy these VEECs. The number of VEECs created is determined by the energy efficiency of the new system, the old system being replaced, and the geographic location of the installation. To be eligible for this rebate, the hot water system installations could be either:

- the replacement of either a decommissioned electric or gas hot water system with an approved gas-boosted solar hot water system;
- the replacement of a decommissioned electric hot water system with an approved electric-boosted solar or heat pump system;
- the replacement of a decommissioned electric storage heater with an approved 5-star gas storage or continuous flow unit; or
- the installation of an approved solar retrofit or pre-heater.

The gas hot water rebate for replacement of peak (day-rate) electric water heaters was introduced to help reduce the running costs and carbon emissions caused by inefficient electric water heaters in households. Rebates are provided for eligible purchases and installations after 1 July 2007 of natural gas and LPG water heaters in households that currently use a peak (day-rate) electric water heater, or a water heater fuelled by wood where the household does not have a second off-peak water heater. Concession card holders who install the five-star instantaneous gas or gas storage hot water heaters (four-plus stars for internal systems) receive a $700 rebate, while others receive a $400 rebate. An additional rebate of $300 is available if the household is a flat or apartment where there is a separate occupancy directly above or below as there is a higher cost associated to gas plumbing installations in such premises.

The Federal Government opened up its $1600 solar hot water rebate to people who lost their homes in the Victorian bushfires in February 2009. To be eligible to obtain a rebate, the rebuilt dwelling must meet the Victorian five-star standard by having a compliant 2000 litre rainwater tank installed which is connected to the dwelling for toilet flushing, and comply with the REBs eligibility criteria (with the exception of replacing an existing electric storage hot water system).

A.4.8 Western Australia

Feed-in tariff scheme

On 1 August 2010, the residential net feed-in tariff scheme commenced in Western Australia. Residential customers receive a net feed-in rate of 40 ¢/kWh for each unit of unused electricity exported to the grid. The scheme includes solar PV, wind and micro-

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75 The Homeowner Insulation Program operated from 3 February 2009 and was replaced by the Home Insulation Program on 1 July 2009. This program aimed to provide incentives for homeowner-occupiers to have insulation installed.

hydro energy technologies. System owners receive the payments from the scheme for 10 years or until the property is sold or leased.

On 20 May 2011, the Western Australia Government announced changes to the feed-in tariff rate from 40 ¢/kWh to 20 ¢/kWh and capped the scheme at 150 MW capacity rather than having an uncapped capacity. These changes will commence from 1 July 2011. The scheme was closed from 1 August 2011 after the 150 MW cap was reached.

Existing feed-in tariff customers were not affected by the rate change.. The reason for the rate change was to ensure the scheme was sustainable and that the benefit householders receive is in line with the cost of their renewable energy systems.

Payments from this scheme are in addition to any other schemes offered by electricity retailers, including the Renewable Energy Buyback Schemes funded by Synergy and Horizon Power. For Horizon, customers will be eligible if they are residential, non-profit organisations or educational institutions with renewable energy systems from 500 W to 10 kW of capacity (for single phase) and from 500 W to 30 kW of capacity (for three phase) in generating capacity. Horizon residential customers receive a net feed-in tariff rate are paid for the excess electricity they generate and sell back to Horizon Power at 18.52 ¢/kWh. For Synergy, customers will be eligible if they are residential, non-profit organisations or educational institutions with renewable energy systems from 500 W to 5 kW of capacity connected to SWIS. Synergy residential customers receive a net feed-in tariff rate of 7 ¢/kWh.

Solar hot water rebate

Western Australia has imposed equivalent standards on water heaters for new buildings from 1 September 2008.

The Western Australian Government offers rebates to householders for the installation of environmentally friendly gas-boosted solar water heaters until 30 June 2013. Two types of rebates are available under this scheme:

- a $500 rebate for installation of natural gas-boosted solar water heaters; and
- a $700 rebate for installation of bottled LPG-boosted solar water heaters (used in areas without reticulated gas).

The eligibility requirements to receive a rebate includes that: the installation relates to new, two or more panel, gas-boosted solar water heaters compliant with the specified Australian Standard; and solar water heaters will be used for private residential purposes.

B Previous studies on the impact of the enhanced RET

This appendix outlines a summary of studies undertaken on the impact of the enhanced RET.

Table B.1 Summary of previous studies on the impact of the enhanced RET

Report details	Report purpose	Modelling methodology	Key conclusions
MMA, Impacts of Changes to the Design of the Expanded Renewable Energy Target, May 2010.	The Department of Climate Change and Energy Efficiency commissioned this report to assess the impact of splitting the expanded RET into the LRET and SRES on electricity prices, investment profile, investment costs and technology mix. Two key scenarios were modelled: • The enhanced RET with a carbon emissions price commencing in 2013; and • The enhanced RET with a carbon emissions price commencing in 2014. These scenarios were compared with a base case of the expanded 20% RET without the split into the LRET and SRES.	There were three main steps to this modelling: 1. Renewable energy market modelling to determine the mix of renewable energy technologies to meet the LRET at least cost. Renewable generation was planted on the basis of meeting the reliability standards and revenues equalling or exceeding the LRMC of the renewable technology; 2. Modelling the uptake of small-scale electricity generation and displacement technologies under the SRES; 3. Electricity market model simulations of the wholesale electricity market to determine the impacts on electricity prices, investments in new conventional generation technologies and resource costs.	There were limited differences between two key scenarios modelled as the short-term delay in the CPRS did not significantly impact on total revenue received by renewable energy producers over the life of the relevant project. As a result, key conclusions are only presented for the enhanced RET with a carbon emissions price commencing in 2013. MMA's key conclusions are as follows: • Total renewable generation is forecast to grow to 66,000 GWh by 2020, with the LRET contributing 39,000 GWh and the SRES 11,000 GWh. This is higher compared to the expanded RET as both large and small scale generation benefits from higher certificate prices. • New large renewable generation is comprised primarily of wind and geothermal, with geothermal contributing 30% of new renewable generation. $2.1 billon in additional expenditure is forecast for large scale generation overall by 2020 compared with the

Report details	Report purpose	Modelling methodology	Key conclusions
			expanded RET • Renewable investment under the SRES will be lower in the initial years compared to the expanded RET but will be higher over the longer term. This occurs as the \$40 certificate price under the SRES is lower than would have been achieved under the expanded RET. • Retail prices are likely to be slightly lower compared to the expanded RET (approximately 1%) due to higher volumes of renewable capacity bidding in at zero.
ACIL Tasman, Modelling Greenhouse Gas Emissions from Stationary Energy Sources, 18 January 2011	The Department of Climate Change and Energy Efficiency commissioned ACIL Tasman to model greenhouse gas emissions from stationary energy sources to 2029-30. The following scenarios were modelled: • A baseline scenario which captured the effect of existing and announced government abatement measures; • A business as usual scenario which excluded the effect of the abatement measures; and • Eight sensitivities.	Four separate models were used by ACIL Tasman. This includes RECMark which was used to investigate the impact of the RET on electricity markets and PowerMark which was used to model dispatch, investment and emissions trends in electricity markets. PowerMark is a dynamic least cost model which optimises existing and new generation operation and new investments. Bidding by plant is represented by an offer band which is based around short run marginal cost and a defined multiple of short run	ACIL Tasman's key conclusions include: • Emissions from the electricity generation sector will grow from 204 Mt CO_2-e in 2007/08 to 216 Mt CO_2-e in 2019/20. • Wholesale prices range from between \$40 and \$50/MWh in real terms up to 2020 before rising once new entrants begin to set price outcomes. • LRET is not forecast to be achieved by 2030, with renewable generation forecast to be around 20,000 GWh short of the LRET

Report details	Report purpose	Modelling methodology	Key conclusions
		marginal cost. RECMark operates on an inter-temporal least cost basis under the assumption of perfect certainty to meet the RET in a least cost manner. The model horizon is set from 2010 to 2060 to account for the economics of renewable plant installed within the scheme period but beyond the end of the subsidy. It projects the marginal REC price required to ensure renewable projects are commercially viable.	and projected GreenPower demand. This occurs as without a REC subsidy or carbon emissions price to increase wholesale electricity prices following 2030, a number of renewable generation projects are not commercially viable. • The LRET is met through to 2016 (but not beyond 2016) with the use of existing banked RECs, which stabilises at around 25,000 GWh in aggregate over the longer term. • REC/LGC prices reach the tax adjusted penalty level in 2017 and remain at this level until 2030 as a result of the supply shortfall. • Wind generation dominates 68% of REC creation, with biomass/bagasse the second largest at 17% of REC creation. Geothermal is expected to only occur under demonstration projects.
SKM MMA, Projections of Greenhouse Gas Emissions for the Stationary Energy Sector, 27 January 2011	The Department of Climate Change and Energy Efficiency commissioned SKM MMA to model the impact of emissions abatement measures and greenhouse gas emissions from the stationary energy sector. Modelling	The modelling of the electricity sector was run using the Strategist model for the NEM, WEM, NWIS, DKIS and Mt Isa. Strategist is a multi-area probabilistic dispatch algorithm that accounts for	SKM MMA's key conclusions include: • The LRET is met with REC/LGC prices below the penalty price. This occurs as a result of declining costs for renewable generation projects and rising wholesale

Report details	Report purpose	Modelling methodology	Key conclusions
	was run under two scenarios: • A baseline scenario which represents the continuation of existing emissions abatement measures; and • A business as usual scenario, where none of the existing government emissions abatement measures are implemented. In both scenarios it was assumed that a CPRS or any other similar carbon pricing mechanism was not implemented.	the economic relationships between generating plants in the system. Bids are based on multiples of marginal cost and are varied to represent the impact of contract positions and price support provided by the dominant market participants. Average hourly market prices are derived from bids and the merit order and performance of thermal plant and inter-regional loss functions.	electricity prices, even in the absence of an emissions trading scheme. • Wind comprises over half of the LRET 2020 target. Around 7,000 MW of wind capacity will be developed to meet the LRET by 2020, with most wind capacity in South Australia, Victoria and NSW. • Geothermal begins ramping up by 2015, with 500MW forecast to be installed by 2020. • Emissions from the electricity generation sector are expected to increase by close to 20% by 2030 relative to 2009. • The SRES will generally have higher average emissions abatement intensity than the LRET. • Emissions abatement from the RET will increased to around 35 Mt CO2-e by 2030, with the biggest growth in abatement from around 2012 to 2016 with the increase in renewable energy projects to meet the LRET.
IES, Will 20% of Australia's Electricity be Produced from Renewable Energy	The purpose of this study was to assess the likelihood of meeting the RET by 2020 and the adequacy of	Limited detail was provided by IES on their modelling methodology and assumptions used. IES used the	IES' key conclusions include: • If the LRET is to be met, it will be

Report details	Report purpose	Modelling methodology	Key conclusions
Sources by 2020?, 6 June 2011	the scheme's current settings. Three options for achieving the RET were modelled: • Option 1: A high carbon emissions price and no other changes to scheme settings; • Option 2: Removal of the LGC surplus and a higher shortfall penalty price (which increases by inflation annually) in the absence of a carbon emissions price; and • Option 3: Increasing liabilities post 2020 in conjunction with carbon pricing to 30% renewable energy penetration by 2030.	MARKAL model to undertake this study. Under this model LGC prices are determined through the whole of life revenue needed by the marginal renewable energy generator required for the LRET to be met, and if the target is not met the tax adjusted penalty price.	met largely as a result of wind energy development rather than through solar power or geothermal. • Under Option 1 a carbon emissions price of at least \$40/tCO2-e in 2010 real dollars would be required by 2020 for the RET to be met. The carbon emissions price would need to be around \$20/tCO2-e at the commencement of the carbon emissions price to motivate the early development of wind farms, and greater than \$60/tCO2-e by 2030 to support investment after the LGC price falls away. • Under Option 2 the LRET can not be met under current settings without a carbon emissions price. If the current surplus of LGC was removed and the current penalty price is increased by inflation each year the LRET would be met by 2021/22. However, LGC prices would remain at the penalty price for most of the modelling period. • Under Option 3 increasing the LRET liabilities to 30% renewable energy penetration by 2030 has a limited impact without a carbon emissions price as the LGC price is at the penalty price from 2019 in

Report details	Report purpose	Modelling methodology	Key conclusions
			any event. However, increasing the LRET liabilities does allow the 2020 target to be met with a lower carbon emissions price than was required in Option 1. Under a carbon emissions price which reaches $40/tCO2-e by 2030 the LRET is almost met by 2020/21 with 38 million certificates created.

B.1 Comparisons between other studies and the AEMC's modelling

Studies by ACIL Tasman and IES are generally consistent with the overall findings reached by the Commission in relation to whether the enhanced RET is likely to be achieved by 2020 and the principal types of technologies (i.e. wind) that will be installed under the scheme. SKM/MMA's studies consider that the LRET and enhanced RET would be met by 2020, however this conclusion is contingent on a significant level of geothermal generation entering the NEM prior to 2020. If geothermal does not develop as quickly as was anticipated by SKM/MMA it is likely that a significant shortfall in the LRET would also eventuate under their modelling.

C Previous studies on security of supply and transmission

Table C.1 Summary of previous studies on the impact of the RET on security of supply and transmission

Report details	Report purpose	Modelling methodology	Key conclusions
ROAM Consulting- Transmission Congestion and Renewable Generation- A Report prepared for the Clean Energy Council 1st October 2010	The report was commissioned to assess the level of congestion under the expanded 20 per cent RET. The focus of the study was on transmission and congestion. Although only inter-regional transmission projects were modelled. impacts on security of supply were not assessed in this study. Four scenarios were modelled: • Scenario 1-Generators chose their location based on capacity factor, ignoring congestion • Scenario 2- Generators chose their location to minimise congestion • Scenario 3- Generators choose their location taking into account both congestion and capacity factor • Scenario 4- Generators choose their location in order to maximise revenue	Wind farms were installed on the basis of advanced and announced projects in the near term, until 2016, and remaining years were modelled on the basis of hypothetical projects. RET requirements were assumed to be met in each year as a minimum. ROAM used its 2-4-C dispatch model (using full set of AEMO constraints) to simulate the NEM and forecast congestion out to 2020. Dispatch was repeated without constraints to assess impacts on generators under the various scenarios. Under each wind distribution scenario 3 transmission options were modelled to assess impacts on total system costs and congestion: • A 400 MW SA-VIC augmentation • A 2000 MW SA-VIC augmentation • A base case of no grid augmentation Transmission constraints were justified for augmentation based on frequency of binding and marginal cost of constraint (MCC) measures A - 5% per cent emissions reduction	The location where investors chose to install wind capacity was the critical in determining the amount of transmission congestion: • Under Scenario 1 most wind locates in TAS and South Australia, which is reflected by an increased level of congestion on interconnectors connecting these regions with the rest of the NEM • Overall system costs (capital + variable+ transmission) are minimised in Scenario 4, which also appears to be consistent with rational commercial behaviour under current rules • Revenues are maximised where generators choose their location based on efficiently trading-off congestion versus capacity factor. This also reduces the REC price required to break even ($51 dollars as opposed to $97 in the high capacity factor scenario) • Nonetheless, there is relatively little difference in overall system costs between scenarios over the modelled period

Report details	Report purpose	Modelling methodology	Key conclusions
		target was assumed in all scenarios	• Each scenario leads to a different distribution of renewable generation which leads to substantially different interconnector development and patterns of congestion • Despite having the highest capacity factors in South Australia and TAS, transmission congestion rapidly becomes problematic for new entry • Interestingly, almost 2000MW less wind generation capacity required under scenario 4 compared with scenario 1 • Modelled augmentations reduce the overall cost of scenario 1, but are not justified under scenario 4. Transmission costs are most significant under scenario 1 • Cost of congestion is relatively small ($60-$270 million) compared with overall costs of $18 billion. But actual impact on pool prices is more significant
ROAM Consulting- the true costs and benefits of the RET-A report prepared for the Clean Energy Council, 25 May 2010	This report assesses both the costs of transmission as well as frequency control ancillary services (regulation) and network control ancillary services (voltage control) required for meeting the 20 % RET	ROAM used an Integrated Resource Planning model (IRP), which computes least cost cooptimised generation and transmission to meet demand in each scenario. Only interconnector augmentations	The overall findings were that the costs of both transmission and frequency control ancillary services are likely to be small: • An important finding is that no transmission is required

Report details	Report purpose	Modelling methodology	Key conclusions
	Three scenarios: • Scenario 1- No LRET, status quo • Scenario 2 - LRET met (wind 0% contribution to reserve levels) • Scenario 3- LRET met (wind 30% contribution to reserve levels	were modelled however, with intra-regional augmentation assumed to occur based on TNSP APRs (to meet jurisdictional reliability requirements). ROAM obtained wind and demand data from various sources including the BOM and location specific wind simulations, at one minute resolution. These were input into a system frequency model to forecast future regulation requirements Above data from IRP and wind modelling was input into 2-4-C model to forecast dispatch outcomes and estimate production costs. Generator bidding is assumed to be at SRMC and FCAS bidding based on historical bids. ROAM forecast an upper bound on voltage control costs by assuming all new forecast wind generation would not install voltage control equipment (rather this cost would be borne by TNSPs and subsequently consumers). Scenarios were modelled both with and without a carbon emissions price ($38 tonne)	specifically to meet the RET, therefore ROAM attributes a $0 MWh transmission cost to the RET • 500MW of Geothermal was assumed by 2020 • Transmission development is required even in the absence of the RET (Scenario 1). This is because no RET would lead to a increase in baseload gas fired generation elsewhere in the NEM, which would need to be imported into SA. • Each scenario requires the same 400MW SA-VIC augmentation • Interestingly, there is not much difference in overall cost based on whether wind contributes 0% or30 % to reserves($0.65MWh) • The regulation requirement strongly depends on geographical dispersion, if moderate dispersion assumed regulation costs are not high • FCAS costs were relatively small due to the low cost of providing regulation services ($0.03 MWh) • Network control ancillary services may increase compared to existing requirements, but this

Report details	Report purpose	Modelling methodology	Key conclusions
			depends on the type of wind generators that connect, however even an upper bound on costs is not significant ($.29 MW/h) • Note the overall cost of transmission in all scenarios is relatively small relative to other costs • With a carbon emissions price in place, the cost of meeting RET is significantly reduced (from about $7.75MW/)h to $4.69MW/h). This is because a carbon emissions price will increase the variable costs of emissions intensive generation, which makes renewable generation more competitive
AEMO- National Transmission Network Development Plan	The purpose of the NTNDP is to provide an independent strategic plan of the network out to 2020 under a range of credible scenarios. Security of supply issues are not examined as part of the NTNDP. There were 5 modelled scenarios : 1. Fast rate of change- characterised by strong emissions reduction targets and economic growth (low and high carbon emissions price sensitivities $93.5 tonne) 2. Uncertain world-characterised by	Network inputs include AEMO constraint equations, loss factors, committed and potential transmission augmentations sourced from Jurisdictional Planning Bodies, and transmission cost estimates SRMC bidding was assumed in this modelling Least cost expansion modelling (MARKAL using MILP) was undertaken, which produces a cooptimised expansion plan (interconnectors only)	Scenario 2 carbon and no carbon case is of particular relevance to the LRET study as it is the most similar. Key outcomes of this scenario are as follows: • Significantly greater levels of wind under the low carbon emissions price versus the no carbon emissions price (8000MW), only 3000 MW in total with no carbon emissions price • Wind locates mostly in Victoria and SA, doubles in SA under low

Report details	Report purpose	Modelling methodology	Key conclusions
	carbon policy uncertainty, strong economic growth. Two carbon sensitivities, zero carbon emissions price and low carbon emissions price ramp up ($44tonne) 3. Decentralised world-move towards distributed generation and demand side management, strong economic growth. medium carbon emissions price ramping up to $62 tonne and also a high carbon sensitivity $93.5 tonne 4. Oil shock and adaption- Oil reserves are in short supply, resulting in low economic growth and high gas prices. CCS and DSP more costly than expected, greater reliance on centralised renewable options 5. Slow rate of change- low economic growth, low investment, low carbon emissions price. Zero carbon emissions price sensitivity	The outputs from the above provides input into power system simulations (using Prophet) that refine least cost expansion by including intra-regional network augmentations required to address congestion (taken from TNSP APRs) Time sequential modelling is also undertaken to identify and remaining congestion	carbon scenario and almost a 4 fold increase in Victoria under low carbon emissions price • Nonetheless, LRET is not met either with a low carbon emissions price or without it by 2020 • No discussion of potential ancillary service or NCAS concerns or costs • It appears that the zero carbon sensitivity drives higher augmentation costs in this scenario due to significant increase in baseload gas, which tends to locate near gas fields and require substantial augmentation • Overall results across all scenarios suggest highest transmission costs are more related to high demand growth than renewable targets (scenario 1 has the greatest cost) • Note that there is some brown and black coal added under the zero carbon emissions price sensitivity in this scenario •
ROAM Consulting- Assessment of FCS and Technical Rules, 3 November 2010, A report prepared	ROAM conducted an analysis of the Frequency Control Service (FCS) requirements in the South west	Load Trace Synthesiser tool was used to grow reference trace according to peak demand and	There is no 5 by 5 minute real time pricing in the SWIS, or ancillary services markets. Variability of wind

Report details	Report purpose	Modelling methodology	Key conclusions
for the Independent Market Operator of Western Australia	interconnected System (SWIS) for different levels of intermittent renewable energy generation. It was also required to provide recommendation on how the cost of FCS should be allocated. Four generation planting scenarios were examined out to 2030: • A strained network case : CPRS - 15 with low demand growth and high gas prices • Minimal change case: CPRS-5 with medium demand growth and moderate gas prices • Low emissions case: CPRS-25 with low demand growth and moderate gas prices • Coal development case: CPRS -5 with high demand growth and high gas prices	energy targets forecasts in each year. Load forecasts were generated based on historic actual loads for both peak and off peak periods using a 10% probability of exceedance Roam obtained wind and demand data from various sources including the BOM and location specific wind simulations, at one minute resolution. These were input into a system frequency model to forecast future load following requirements Determining the output of new wind farms at new locations was performed using WETS, ROAM's proprietary wind forecasting tool, based on date obtained above and the manufacturer provided Turbine Power Curves. The Turbine Power Curves are then used to convert wind speeds into actual generation for input into the 2-4-C market dispatch model. This model then calculates load following costs Load Trace Synthesiser tool was used to grow reference trace according to peak demand and energy targets forecasts in each year. Load forecasts were generated based on historic actual loads for both peak and off peak periods using	generation is primarily managed by the continual dispatch of rapid response OCGT plant provided by Verve energy (load following). Intermittent output is also not scheduled. Key conclusions of ROAM's work are as follows: • Under strained network case 1045 MW installed wind capacity was forecast by 2020 and 1460 by 2030. Low emissions is next highest with 745 MW • The load following requirement increases substantially in reasons to higher penetrations of wind generation. For example in the strained network scenario by between 5% and 40 % of the capacity of new installed wind farms, or from current 60MW to 300MW • Under strained network scenario costs would increase from about $10 million in 2009 to between $55 and $65 million per annum by 2015. Assuming existing rules continue • Most ancillary services costs are recovered from load, if wind generators were made responsible for the load following

Report details	Report purpose	Modelling methodology	Key conclusions
		a 10% probability of exceedance	they cause could be up to $16MWh. Which is a very substantial cost for new entrants • Cost escalate rapidly in the early years because the load following requirement increases rapidly • Costs could be substantially higher again if higher gas prices assumed • There is no market for the provision of ancillary services, which means provision of load following needs to occur through contracting with OCGT plant. This increases costs of provision • ROAM considered that no additional inertia or reactive power capability is needed for wind generators

C.1 Comparisons between other studies and the AEMC's modelling

Results for the ROAM's modelling in the current study are consistent with findings in other studies. In particular, ROAM founds that ancillary services and transmission costs are likely to be small relative to the overall cost of the LRET, although ancillary services costs are likely to be significant in the SWIS due to the absence of a market for such services. Further, consistent with findings by AEMO in modelling its NTNDP, augmentation requirements are largely driven by demand growth rather than meeting the LRET.

Of note is that under the “uncertain world” scenario of the NTNDP, which is most consistent with our scenarios, the zero carbon sensitivity leads to higher augmentation costs relative to if low carbon emissions price was in place. This was explained by the larger penetration of open cycle gas turbines under a zero carbon emissions price scenario, which would require increased utilisation of more remote gas fields over time, increasing augmentation requirements. ROAM's modelling presented a similar conclusion for this report. Under ROAM’s modelled results more augmentation over the long term was required for the counter factual (no LRET) versus the reference case (LRET forced), as higher levels of closed cycle gas turbines were anticipated under the counterfactual.

Abbreviations

ABS	Australian Bureau of Statistics
AEMC's	Australian Energy Market Commission's
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGC	Automatic Generation Control
CPRS	Carbon Pollution Reduction Scheme
DCCEE	Commonwealth Department of Climate Change and Energy Efficiency
DKIS	Darwin/Katherine Interconnected System
ESIPC	Electricity Supply Industry Planning Council
FCAS	frequency control ancillary services
FiTs	Feed-in-Tariffs
LGCs	Large Scale Generation Certificates
LRET	Large Scale Renewable Energy Target
LRMC	long run marginal cost
MCE	Ministerial Council on Energy
MRET	Mandatory Renewable Energy Target
NCAS	network control ancillary services
NEM	National Electricity Market
NSCAS	network support and control ancillary services
NTNDP	National Transmission Network Development Plan
ORER	Office of the Renewable Energy Regulator
RECs	Renewable Energy Certificates
RET	Renewable Energy Target
SCO	Standing Committee of Officials
SEIFA	Socio-Economic Indexes from Areas
SGU	small generating unit
SRES	Small Scale Renewable Energy Scheme
STCs	Small Scale Technology Certificates
SWIS	South West Interconnected System

TNSPs	transmission network service providers
WA	Western Australian
WA IMO	Western Australian Independent Market Operator
WEM	Western Australian Electricity Market