20 September 2012

Committee Secretary
Senate Select Committee on Electricity Prices
PO Box 6100
Parliament House
Canberra ACT 2600

Lodged online: Senate Select Committee on Electricity Prices

Senate Select Committee on Electricity Prices

TRUenergy welcomes the opportunity to make a submission to the Senate Select Committee on Electricity Prices.

TRUenergy is one of Australia's largest energy companies, providing gas and electricity supply to over 2.7 million household and business customers. TRUenergy owns and operates a multi-billion dollar portfolio of energy generation and storage facilities across Australia including coal, gas and wind assets. TRUenergy is committed to developing low and zero emission energy generation technologies across a range of clean energy initiatives.

Australia's electricity prices have risen in recent years. This has put pressure on households and businesses and put electricity prices squarely in the public debate. TRUenergy has been on the front line of rising prices because, unlike other parts of the supply chain, retailers deal directly with customers. This is despite the fact that the drivers of price increases are largely outside our control.

While some drivers of rising prices may be unavoidable, such as aging assets, others are within the direct control of governments or can be influenced by the right suite of policies. Many of the drivers are not well understood by the community. This inquiry is therefore an important opportunity to educate the community on the drivers of rising electricity prices and importantly, identify the decisions that all stakeholders – policy makers, industry and consumers – can take to prevent unnecessary increases in electricity prices in the future.

One timely opportunity to reduce pressure on future electricity prices is the Climate Change Authority's current review of the Renewable Energy Target (RET).

While the RET was intended as a "20% by 2020" target, recent reductions in electricity demand mean it is likely to overshoot and be a 26% target. Estimates by ACIL Tasman commissioned by TRUenergy show that adjusting the RET to achieve the 20% target would reduce the RET subsidy by $25 billion to 2030 compared to its current projected level.[1] This would almost halve the total cost of the scheme in 2020 for an average customer.

There is a diversity of views on the future of the RET among industry and stakeholders. In contrast to calls to remove the RET entirely, we are strong supporters of continuing the scheme. We have and continue to make significant investments in renewable energy, including the Cathedral Rocks and Waterloo wind farms and recent agreements with the 107MW Boco Rocks and 108MW Taralga wind projects. But unlike calls to maintain the status quo, we consider that the scheme should not be isolated from changes in demand. Instead, we see a middle ground reform path of recalibrating the target as the most sensible way to meet the original 20% policy intent and reducing electricity costs for consumers.

In the remainder of this submission we examine the drivers of recent increases in electricity prices and outline key policy responses to reduce pressure on energy prices and bills in the future. We also elaborate on how changes to the RET could be implemented.

Drivers of prices increase

While the magnitude of electricity price increases over recent years varies by state, the drivers are similar. The main drivers in absolute terms are increased network costs and the fasted growing in percentage terms is environmental scheme costs (including the carbon price impact).[2]

Network costs

Network prices are determined by regulation. The drivers of rising network costs include the replacement of aging infrastructure and peak demand growth. The Draft Energy White Paper[3] has highlighted peak demand growth – which means more infrastructure is required to supply power for only a small amount of time each year – as a key challenge for the Australian electricity sector. The Productivity Commission has found that peak demand growth has a strongly negative productivity effect on the electricity sector.[4] All else equal, lower energy sector productivity leads to higher prices.

---

[1] The ACIL Tasman modelling has been attached to this submission.

[2] IPART Independent Pricing and Regulatory Tribunal changes in regulated electricity retail prices from 1 July 2012. Electricity Final Report June 2012.

[3] Draft Energy White Paper 2011: Strengthening the foundations for Australia's energy future. Pg.172.

[4]Topp, V. and Kulys, T. 2012, *Productivity in Electricity, Gas and Water: Measurement and Interpretation*, Productivity Commission Staff Working Paper, Canberra.

Environmental schemes

Given the interaction between the electricity sector and the environment, governments throughout Australia have imposed significant environmental schemes onto the energy sector. These ranged from national schemes – such as carbon pricing and the RET – to jurisdictional schemes such as small scale premium feed in tariffs and 'white certificate' energy efficiency schemes. These schemes increase the cost of electricity supply, which is recovered by higher electricity prices. In some cases, such as premium feed in tariffs, there are distributional impacts as the cost of the subsidy to recipients is shared across other energy users.

Wholesale costs

Wholesale electricity is traded through the highly competitive National Electricity Market (NEM). NEM prices have been subdued in recent years – the Energy Supply Association notes that in 2010-11, on a time weighted basis, average real spot prices for all regions of the NEM were at their lowest level since market start in 1998.[5] This has meant that wholesale electricity prices have not been a significant driver of retail electricity prices.

Looking forward there are pressures on wholesale prices, including the cost of carbon and potentially a rising gas price as Australia's east coast gas market becomes linked to international markets via LNG and higher cost resources are brought on as lower cost resources are depleted. It will be important that the NEM is allowed to function without interference so that these cost pressures can be digested as efficiently as possible.

Retail costs

Retail costs are a small percentage of overall costs. However, increasing regulatory requirements – such as bill benchmarking, carbon inserts and messages – adds to costs and puts upward pressure on prices. A particular driver of costs is inconsistent regulatory requirements across the multiple jurisdictions that TRUenergy operates in.

For instance, considerable resources were required in preparation for the introduction of the National Energy Customer Framework (NECF) which was supported by all NEM States. The NECF sought to align the regulatory frameworks in all jurisdictions and centralise compliance and reporting to ensure that all energy consumers had access to the same customer protections and allowed retailers to gain efficiencies as process, collateral, staff training and reporting could be standardized across the NEM. The decision by some states to not implement NECF has resulted in a duplication of compliance frameworks, and consequently increased costs.

[5] esaa submission, *National Electricity Amendment (Potential Market Power in the NEM) Rule 2011: Directions Paper*, 24 November 2011.

Key policy responses

There are a number of policy responses to reduce cost pressures on the electricity system.

Tackling the peak demand problem through price signals

Rising peak demand occurs in part because in most cases consumers are not aware of how their individual actions – such as turning on appliances at peak times – contributes to stress on the entire system and ultimately an increase in prices, including for themselves. An example provided in the Federal Government's draft Energy White Paper is that while it may cost around $1500 to purchase and install a 2 kilowatt (electrical input) reverse-cycle air conditioner, such a unit could impose costs on the energy system as a whole of $7000 when adding to peak demand.[6]

In order to address this issue, a suite of policies is required. Consumers cannot make fully informed decisions without the right price signals that communicate how their actions lead to costs on the system. This means that more flexible pricing arrangements, such as "time of use" pricing, are necessary. However, a barrier to more flexible pricing is retail price regulation, which inhibits the range of offers retailers can make to customers. In addition, more advanced metering technology, to replace current analog meters, is needed. Advanced meters, innovative pricing, the removal of price regulation and a regulatory framework that does not stifle innovation or increase costs are the keys to improving the productivity of electricity supply.

There are many variants of time of use pricing and different ways advanced metering can be deployed into businesses and households. Working through the options to arrive at efficient approaches is a challenge for all stakeholders. Significant amounts of work have been completed and are underway. Importantly, as experiences in Victoria shows, it is necessary to have a high level of community understanding, engagement and support to make these reforms work. We consider that governments, such as through this inquiry, in partnership with industry, have an important role in helping explain to the community the peak demand problem and the necessary solutions.

Creating a competitive market

Competitive markets are the cornerstone of the Australian economy. They should be the goal for the electricity industry as well. Competitive markets allow for efficient electricity prices – that is prices that are high enough to cover costs and allow the industry to be sustainable but kept as low as possible through competitive behavior. They also allow for other benefits to consumers, such as choice, innovation and customer service.

---

[6] Draft Energy White Paper 2011: Strengthening the foundations for Australia's energy future. Pg.172. Available at: http://www.ret.gov.au/energy/Documents/ewp/draft-ewp-2011/Draft-EWP.pdf

While Australian jurisdictions have begun the journey to a competitive market, more needs to be done. A priority is to remove retail electricity price regulation, as Victoria has done (and a number of jurisdictions have done with retail gas), to bring electricity in line with almost all goods and services in competitive parts of the Australian economy.

Retail price regulation inhibits companies from developing products and services which could relieve upward pressure on electricity prices – such as more flexible time of use pricing arrangements to combat the peak demand problem – and help consumers to manage their electricity use in a smarter way.

Retail price deregulation will allow electricity prices to be automatically set by market processes to an efficient level. Competition and retail price deregulation will provide benefits for lower income consumers as it encourages a diversity of product offerings. For instance, it gives retailers the flexibility to offer different combinations of high/low fixed/variable tariffs, which gives consumers with different consumption levels options to find the most suitable tariff.

Nonetheless, there are consumers who will struggle to pay the efficient price of electricity. The solution to assisting these consumers is not by artificially suppressing retail prices. This approach subsidises all energy users – which is regressive – and has been tried and failed in a number of Australian jurisdictions.

Instead, targeted measures to address hardship are required. Addressing energy hardship is a shared responsibility of governments, energy retailers, community groups and individuals. TRUenergy has a hardship policy and hardship program that sets out how we deal with the issue. However, consistent with the broader approach to social welfare, governments have the primary role in ensuring that the community's social welfare expectations are met through transfer payments and other measures.

Efficient environmental policy and the Renewable Energy Target

Environmental schemes add to the cost of electricity supply and therefore prices. The challenge is therefore to design these schemes as effectively and efficiently as possible to keep price increases to a minimum.

To some extent this has begun to happen, such as reforms to jurisdictional feed in tariffs and the removal of the price floor in the carbon pricing mechanism. That said, there are outstanding concerns with the carbon price mechanism, such as the proposed restriction on the import of Certified Emission Reduction units, which will artificially raise carbon prices in Australia. More generally, however, with the carbon price in place, there is an opportunity to remove and rationalize inefficient and duplicative environmental schemes.

One particular environmental policy where reform would reduce pressure on electricity prices is the RET. The RET is currently undergoing statutory review by the Climate Change Authority.

TRUenergy supports a 20% RET by 2020 and under the RET framework, has become one of Australia's leading investors in renewable energy. Through our involvement in Roaring 40s we have been extensively involved in the development of wind farms, and also contributed to fostering renewable development in developing countries. In 2011 we expanded our renewable energy portfolio through our acquisition of Waterloo and 50 percent share of the Cathedral Rocks wind farms following winding up of the Roaring 40s joint venture. Since then TRUenergy has also been a driving force in supporting independent developers of commercially viable wind projects through agreements with a variety of projects across New South Wales and Victoria including the 107MW Boco Rocks and 108MW Taralga wind projects.

The RET provides a certificate based subsidy to renewable energy technologies, which allows them to be competitive with non-renewable technologies in meeting demand growth or replacing retirements from the existing fleet of generators.

The current RET was established when strong growth in demand for energy was projected. Demand forecasts have now decreased significantly such that the current scheme design would amount to an effective 26 per cent target by 2020. This means that continuation of the scheme in its current form would impose additional costs on customers and not align with the scheme's original objective of achieving a 20% by 2020 target. Analysis commissioned from ACIL Tasman estimates that the RET, in its current form, would provide a nominal subsidy of $53.3 billion over the life of the scheme; this subsidy increases the price of electricity for end users.

We believe that the reduction in forecast demand growth highlights the need to build greater flexibility into the RET scheme[7] to ensure it is a "real 20 per cent by 2020" target. In our submission to the Climate Change Authority,[8] we propose options to implement a real 20% target through an adjustment mechanism. The proposed approach balances investor confidence with the flexibility to achieve a "real 20 per cent by 2020.

Analysis by ACIL Tasman estimates that a real 20% target would reduce the RET subsidy to $28.1 billion; a reduction of $25 billion compared to the current scheme design. This would almost halve the total cost of the scheme in 2020 for an average customer.

Our approach to the RET review puts us in the middle of the diversity views on the future of the RET. In contrast to calls to remove the RET entirely, we are strong supporters of continuing the scheme. But unlike calls to maintain the status quo, we consider that the scheme should not be isolated from changes in demand. Instead, we see a middle ground reform path of recalibrating the target as

[7] Noting that if demand growth recovered and exceeded previous expectations then this flexibility would also support higher targets.

[8] Which is available on the Climate Change Authority's website and which we would be happy to provide a copy of.

the most sensible way to meet the original 20% policy intent and reducing electricity costs for consumers.

Importantly, as Australia's total net emissions are determined under the Clean Energy Future policy package, this change would not affect Australia's contribution to climate change abatement. There would only be change in the composition of abatement.

Efficient regulation of networks

As outlined above, network prices are a key driver of rising electricity prices and are determined by regulation via the Australian Energy Regulator. The network regulatory framework is currently under review through multiple processes, including the Review of Limited Merits Review and a number of Australian Energy Market Commission Rule changes.

While there has been considerable focus on increasing network prices, the answer is not simply to cut network expenditure per se. There is a trade-off between the reliability of the electricity network and its price, and Australians rightfully demand a high level of reliability. Instead, the challenge is to design and implement a regulatory framework that delivers an efficient level of network expenditure.

Increases in network prices flow directly through to final prices to consumers via retailers, such as TRUenergy, who pass them on. Going forward, retailers – who are well-informed about the industry and have regulatory resources – will need to become more closely involved in network regulatory processes to ensure efficient outcomes on behalf of their customers.

The ownership of electricity networks remains an ongoing question in the NEM. A number of pieces of analysis comparing outcomes between privately and publicly owned networks has found lower price outcomes for consumers in privately owned networks.[9] TRUenergy supports private ownership of network assets as an opportunity to improve price/reliability outcomes for customers and encourages Governments to pursue reform in this area.

Energy efficiency

Energy efficiency is about empowering customers and using technology and information to help Australian households and businesses use the right amount of energy for their needs. It is about getting the balance right between consumption of energy and other goods and services e.g. trading off the higher upfront costs of an energy efficient appliance versus lower running costs.

[9] See for instance, Mountain, B.R., May 2011. *Australia's rising electricity prices and declining productivity: the contribution of its electricity distributors.* Energy Users Association of Australia.

Improving the energy efficiency of the Australian economy and households firstly requires getting the right price signals that reflect the cost of energy and how that cost varies throughout the day/year e.g. the peak demand problem.[10] Addressing this will put downward pressure on prices at a system wide level.

Secondly, directly addressing the barriers to energy efficiency – such as inadequate information, access to capital and split incentives – will assist individual consumers to be more energy efficient and lower their bills. TRUenergy would be happy to outline to the Committee how we are helping Australians with efficient solutions to improve their energy efficiency. The outlook for energy efficiency is stronger under a competitive retail electricity industry as this provides the incentive for energy retailers to offer energy efficiency solutions to customers.

Conclusion

Rising electricity prices have pushed the issue to the forefront of public debate. TRUenergy considers that this inquiry is an important opportunity to build on the range of policy and regulatory work underway and highlight key steps that can be taken to prevent unnecessary increases in electricity prices in the future. In particular, we consider that an adjustment to the RET is a key area for the Committee to explore.

Yours sincerely

Temay Rigzin
Corporate Strategy and Advocacy Manager

[10] This issue is addressed in detail in the chapter 6 of the Draft Energy White Paper on energy productivity.

Final report

Under Embargo until 1am 7th September 2012

Achieving a 20% RET

Costs of current legislation and possible modifications

Prepared for TRUenergy

5 September 2012

ACIL Tasman

Economics Policy Strategy

Reliance and Disclaimer

ACIL Tasman Pty Ltd

ABN 68 102 652 148
Internet www.aciltasman.com.au

Melbourne (Head Office)
Level 4, 114 William Street
Melbourne VIC 3000

Telephone (+61 3) 9604 4400
Facsimile (+61 3) 9604 4455
Email melbourne@aciltasman.com.au

Brisbane
Level 15, 127 Creek Street
Brisbane QLD 4000
GPO Box 32
Brisbane QLD 4001

Telephone (+61 7) 3009 8700
Facsimile (+61 7) 3009 8799
Email brisbane@aciltasman.com.au

Canberra
Level 2, 33 Ainslie Place
Canberra City ACT 2600
GPO Box 1322
Canberra ACT 2601

Telephone (+61 2) 6103 8200
Facsimile (+61 2) 6103 8233
Email canberra@aciltasman.com.au

Perth
Centa Building C2, 118 Railway Street
West Perth WA 6005

Telephone (+61 8) 9449 9600
Facsimile (+61 8) 9322 3955
Email perth@aciltasman.com.au

Sydney
Level 20, Tower 2 Darling Park
201 Sussex Street
Sydney NSW 2000
GPO Box 4670
Sydney NSW 2001

Telephone (+61 2) 9389 7842
Facsimile (+61 2) 8080 8142
Email sydney@aciltasman.com.au

For information on this report

Please contact:

Owen Kelp
Telephone (07) 3009 8711
Mobile 0404 811 359
Email o.kelp@aciltasman.com.au

Contributing team members

Guy Dundas
Martin Pavelka
Cara Chambers

Contents

Executive summary **iv**

1 Introduction **1**
- 1.1 Scope of work 1

2 Methodology **2**
- 2.1 Wholesale electricity 2
- 2.2 LRET 3
- 2.3 SRES 5

3 Base case **7**
- 3.1 Scenario design and key inputs 7
- 3.2 Wholesale market results 8
  - 3.2.1 NEM outcomes 8
  - 3.2.2 LRET outcomes 10
  - 3.2.3 SRES outcomes 13
- 3.3 Summary of RET costs 14

4 'Real 20%' LRET **16**
- 4.1 Scenario design and key inputs 16
- 4.2 Wholesale market results 17
  - 4.2.1 NEM outcomes 17
  - 4.2.2 LRET outcomes 18
  - 4.2.3 SRES outcomes 20
- 4.3 Aggregate RET costs 20

5 Comparisons of scenarios **23**

List of figures

Figure 1 LGC supply demand balance: 2001 to 2030 4
Figure 2 Projected NEM pool price outcomes: Base case 9
Figure 3 NEM new entrant and retirement profile: Base case 10
Figure 4 LGC surrenders and banked LGCs 2012-2030: Base case 11
Figure 5 LGCs created by fuel source and by jurisdiction: Base case 12
Figure 6 Projected LGC prices and current futures prices: Base case 12
Figure 7 Projected STC creation rates by technology: Base case 13
Figure 8 Indicative annual individual household cost: Base case 15
Figure 9 Revised 'Real 20%' target for the LRET compared with currently legislated target 17
Figure 10 NEM new entrant and retirement profile: 'Real 20%' scenario 18
Figure 11 LGC surrenders and banked LGCs 2012-2030: 'Real 20%' scenario 19

Figure 12	**LGCs created by fuel source and by jurisdiction: 'Real 20%' scenario**	19
Figure 13	**Projected LGC prices and current futures prices: 'Real 20%' scenario**	20
Figure 14	**Indicative annual individual household cost: 'Real 20%' scenario**	22
Figure 15	Indicative annual individual household cost of RET: Scenario comparison	24

List of tables

Table 1	Carbon prices assumed: Base case	7
Table 2	Projected NEM pool price outcomes: Base case	9
Table 3	Summary of SRES projections: Base case	13
Table 4	RET cost summary: Base case	14
Table 5	**Revised 'Real 20%' target for the LRET**	16
Table 6	**RET cost summary: 'Real 20%' scenario**	21
Table 7	Projected aggregate subsidies paid through RET	23

Executive summary

ACIL Tasman has been engaged by TRUenergy to provide a market projections report specifically examining the impact of the current and possible variants of the Renewable Energy Target (RET) legislation.

The analysis considered two scenarios:

- A Base case outlook which reflects the legislated fixed GWh targets under the Large-scale Renewable Energy Target (LRET) and the uncapped Small-scale Renewable Energy Scheme (SRES)
- **A 'Real 20%' LRET** in which the fixed GWh targets are reduced such that it reached 20% of anticipated liable demand by 2020.

In modelling these scenarios ACIL Tasman utilised its *PowerMark* and *RECMark* models to evaluate impacts at the wholesale level and also implications for the direct cost upon residential users.

The modelling demonstrated that modifications to the RET will have some short-term impacts upon wholesale electricity price outcomes, however the amount and timing of new entrant fossil fuelled capacity will adjust accordingly such that the wholesale market will not deviate from its equilibrium price path.

The analysis has therefore focused upon the direct costs upon electricity users resulting from the renewable energy schemes.

In its current form, the RET is a significant subsidy with an estimated total direct value of $53.3 billion (in nominal terms) within the Base case as shown in Table ES 1. Over 80% of this is associated with the LRET, where costs are anticipated to grow over time, in line with increasing fixed GWh targets. The direct costs of subsidising small-scale systems, whilst currently high due to the influence of Solar Credits multiplier, is projected to decrease over time.

The 'Real 20%' scenario which has lower GWh targets in accordance with the current demand outlook reduces the aggregate direct cost to $28.1 billion ($25.2 billion lower than the Base case). This adjustment results in the 2020 target falling to around 28,000 GWh compared with the current 41,000 GWh level. The lower target results in lower certificate prices, and a lower level of large-scale renewable deployment (wind in the NEM is around 3,300 MW lower by 2020 under this scenario).

Table ES 1 **Projected aggregate subsidies paid through RET**

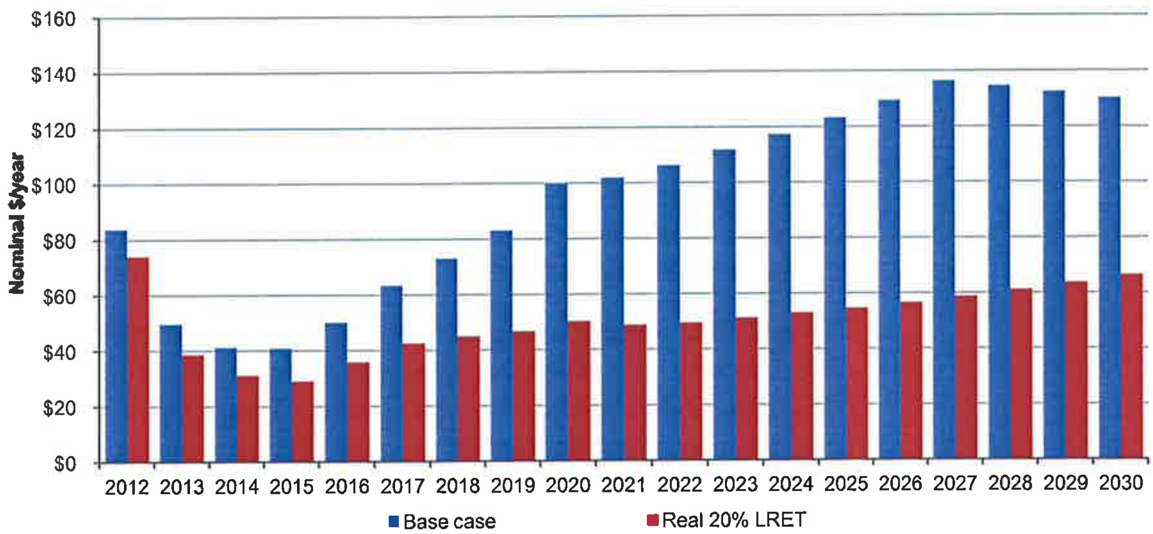
Scenario	Aggregate LRET subsidy 2012-2030	Aggregate SRES subsidy 2012-2030	Aggregate RET subsidy 2012-2030
	$ billion	$ billion	$ billion
Base case	43.2	10.1	53.3
'Real 20%' LRET	17.9	10.1	28.1

Note: Nominal dollars.
Data source: ACIL Tasman projections

Figure ES 1 shows indicative annual direct costs of the RET for a typical residential household consuming 7 MWh per annum. Scaling back obligations under the RET through the lower GWh targets has the potential to reduce pressures on retail electricity prices, whilst still maintaining the stated policy intent of 20% renewables by 2020.

In summary, the total direct cost upon households from the RET scheme under each scenario over the period 2012 to 2030 (in nominal terms) is $1,800 under the Base case **and $960 under the 'Real 20%' LRET**. Therefore moving from the current scheme to a Real 20% LRET is projected to save an average household a total of $840 over the period in nominal terms.

Figure ES 1 **Indicative annual individual household cost of RET: Scenario comparison**



Note: Based on household consumption of7 MWh per year; includes 10% notional energy losses; excludes GST. Nominal dollars based on assumed inflation of 2.5%. Includes both LRET and SRES costs
Data source: ACIL Tasman estimates

1 Introduction

ACIL Tasman has been engaged by TRUenergy to provide a market projections report specifically examining the impact of the current and possible variants of the Renewable Energy Target (RET) legislation.

This report presents the methodology and results of this market modelling exercise.

1.1 Scope of work

ACIL Tasman was tasked with providing a modelling report examining the two renewable scenarios set out below.

Current scheme: Base case outlook

The first scenario examines the impact of the current LRET legislation which mandates a fixed 41,000 GWh of large-scale renewable energy by 2020 combined with the existing uncapped SRES which may result in aggregate compliance rate – the combination of the Renewable Power Percentage (RPP) and Small-scale Technology Percentage (STP) – being well above 20% in 2020.[1]

A 'Real 20%' renewable target

A second scenario examines an alternative policy where support for renewables **is limited to a** 'Real **20%' level.**

This would include a modified target for a combined LRET such that it reached 20% of anticipated liable demand by 2020. The SRES scheme would remain in its current uncapped form. Based on projections of up-take of small scale systems, this would likely results in overall renewable energy delivered to customers exceeding the 20% level.

The modelling covers the period 2012 through to 2030 and is NEM focussed only, although the modelling does include assumptions for non-NEM regions in order to calculate RPP and STP values. The results include wholesale, generation investment split by technology type, LGC/STC prices (including penalty payments), RPP/STP estimates and direct subsidy costs.

[1] It should be noted that the original expanded renewable energy target was based on an incremental 45,000 GWh of renewable energy by 2020, notionally 20% when new (45,000 GWh) was added to existing baselined generation (roughly 15,000 GWh) against anticipated 2020 Australian electricity demand of 300,000 GWh.

2 Methodology

This section provides an overview of the methodology employed within this study in estimating the impacts of the SRES/LRET upon market outcomes.

2.1 Wholesale electricity

ACIL Tasman has undertaken the wholesale electricity market modelling component using its in-house market simulation model – *PowerMark*. *PowerMark* has been developed over the past 13 years in parallel with the development of the NEM. The model is used extensively by ACIL Tasman in simulations and sensitivity analyses conducted on behalf of industry clients.

PowerMark is a complex model with many unique and valuable features. It provides insights into:

- wholesale pool price trends and volatility
- variability attributable to weather/outages and other stochastic events
- market power and implications for generator bidding behaviour
- network utilisation and generation capacity constraints
- viability of merchant plant and regional interconnections
- contract and price cap values
- timing, size and configuration of new entrant generators
- demands for coal, gas and other fuels; and
- the cost outlook for buyers of wholesale electricity.

PowerMark effectively replicates the AEMO settlement engine — SPD engine (scheduling, pricing and dispatch). This is achieved through the use of a large-scale LP-based solution incorporating features such as quadratic interconnector loss functions, unit ramp rates, network constraints and dispatchable loads. The veracity of modelled outcomes relative to the AEMO SPD has been extensively tested and exhibits an extremely close fit.

The key input parameters within any *PowerMark* simulation are:

- Energy and peak demand projections
- Existing supply including all key operational parameters for power stations down to unit level
- Greenhouse gas abatement policies such as explicit carbon pricing through the Clean Energy Future (CEF) legislation
- Non-renewable new entrant assumptions for the suite of candidate technologies assumed in the modelling
- Construction of generator offers and offer curves (bidding behaviour)

- Plant availability (planned and forced outage rates)
- Transmission interconnection assumptions.

The model has been run at an hourly resolution over the period July 2012 to December 2030. Conventional (fossil fuel) new entrants are introduced into the scenario on a commercial basis and incumbent generators are retired if net pool earnings fall below levels required to sustain fixed operating costs.

All assumptions used in the modelling are taken from publicly available or in-house information and databases maintained by ACIL Tasman.

2.2 LRET

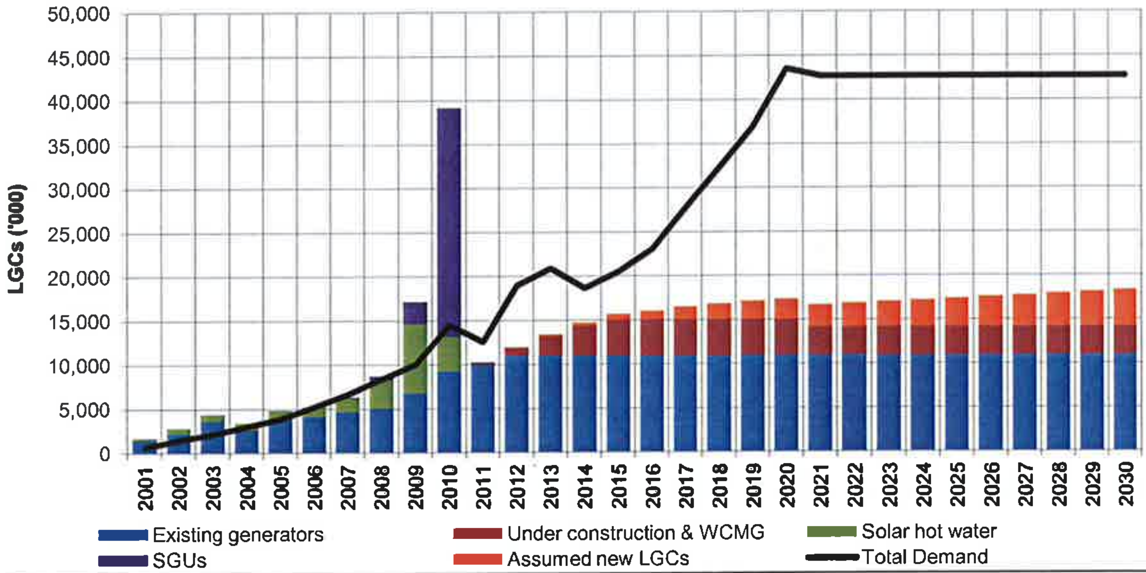
Projections of large-scale renewable development and Large-scale Generation Certificate (LGC) prices have been developed through the use of *RECMark* – ACIL Tasman's model of the LRET. The model utilises a large-scale linear programming solver with an objective function to comply with the LRET in a rational, least cost manner. It operates on an inter-temporal least cost basis, under the assumption of perfect certainty.

The model horizon covers the period from 2010 to 2060. This extends well beyond the end of the LRET (2030) in order to account for the economics of renewable plant installed within the period of the scheme, but beyond the end of the subsidy. In essence the model develops new renewable projects on a least cost basis across Australia and projects the marginal LGC price required to ensure all projects that are projected to be developed are commercially viable. In this sense the LGC price reflects the subsidy required to make the most marginally developed project just profitable over the life of the LRET scheme. The LGC price series extends through to 2030 and takes into account all inputs and constraints.

The model simulates the development and operation of new entrant plant based on technology cost settings and project specific parameters within the inputs. The model will naturally develop the lowest cost projects first, subject to any build and capacity limitations applied. Once developed, each of these new entrant projects creates LGCs over its economic life, based on its maximum capacity factor and marginal loss factor (MLF). Combined with output assumptions for existing projects, this allows results to be reported on LGC creation by technology and fuel mix.

Figure 1 shows the historical and forward-looking supply-demand balance under the LRET. *RECMark* seeks to fill the gap at least cost, taking into account the large banked certificate position. The model produces a LGC price projection and the projected level of development of wind, geothermal and utility-scale solar projects.[2]

Figure 1 **LGC supply demand balance: 2001 to 2030**



Note: Existing generators include all facilities registered within the REC Registry. WCMG = Waste Coal Mine Gas. SGUs = Small Generating Units (PV). Assumed new LGCs represent contributions from niche technologies (Landfill gas, Bagasse, Wood, Sewage Gas, and embedded solar PV above 100 kW in size) which are not explicitly modelled within RECMark. Total demand includes mandated demand under LRET, allowance for WCMG, operation of desalination plants, GreenPower and other voluntary surrenders.

Data source: ACIL Tasman analysis

To translate the aggregate LRET target for any given year into a mechanism by which individual electricity users that are liable under the scheme ('liable entities') can determine how many LGCs they must purchase and acquit, the LRET legislation requires the Clean Energy Regulator (CER) to publish a Renewable Power Percentage (RPP) for each year.

The RPP is determined ex-ante by the CER and represents the relevant year's LRET target as a percentage of the estimated volume of liable electricity consumption throughout Australia in that year. Accordingly, the RPP also represents the percentage of any individual user's liable electricity consumption that must be acquitted through the surrender of LGCs for the relevant compliance year.

Entities that undertake eligible emissions-intensive activities may be allocated Partial Exemption Certificates (PECs), which can be used to reduce their total liability under the LRET (or passed on to a retailer making wholesale acquisitions on their behalf).

---

[2] The development of landfill gas, bagasse, wood, sewage gas, and embedded solar PV above 100 kW in size as assumed exogenously to the model.

Reflecting on the origins of the PEC regime from the CPRS framework, two categories of emissions-intensive activities are defined under the LRET:

- **'highly emissions-intensive' activities, attracting exemption at a 'headline'** rate of 90%
- **'moderately emissions**-inten**sive' activities attracting exemption at a 'headline' rate of 60%.**

For any individual entity, LRET liability under the PEC regime is defined as **the level of 'reduced acquisitions' multiplied by the RPP, where:**

In this way, the existence of partial exemption certificates reduces the liability of entities undertaking EITE activities. Further, the RPP is defined in aggregate by reference to reduced acquisitions rather than relevant acquisitions as below:

This means that the existence of PECs increases the RPP by reducing the denominator of the above equation which means that the larger the exemptions, the larger the RPP. In effect some of the partial exemption is recaptured through the higher RPP from those firms with the partial exemptions (to the extent that they are not exempt), although most of the exemption is spread across non-exempt users. It is necessary to estimate both the level of relevant acquisitions and partial exemptions in any future year to estimate the likely RPP.

2.3 SRES

Outcomes under SRES comprise of two main components:

- Uptake of small-scale generation systems: solar PV and solar water heater installations, the level of which effectively sets the Small-scale Technology Percentage (STP)
- The cost of Small Technology Certificates (STCs).

The SRES supports small-scale generation through upfront deeming (15 years for PV systems and 10 years for SWH). A certificate is equivalent to 1 MWh of electricity deemed to be displaced by the installation of the system.

For this exercise we have relied upon PV installation projections undertaken by AEMO as part of the 2012 National Electricity Forecasting Report (NEFR)[3]

[3] AEMO, National Electricity Forecasting Report, June 2012

under its medium planning scenario. A proportion of these installations were assumed to be above 100 kW in size, such that they create LGCs under LRET rather than STCs under SRES.

Projections for solar water heaters were developed through a stock replacement model and drew upon previous work ACIL Tasman has completed for the AEMC in late 2011.[4]

SWH uptake is heavily affected by policy, regulatory and stock replacement drivers on top of direct economic (e.g. cost) drivers. Accordingly, we consider that a replacement stock model that captures key trends in replacement and new building SWH installations, and drivers including technology restrictions, technology options, availability of natural gas and new dwelling construction rates, provides a reasonable basis for projected up-take.

The cost of STCs is a function of supply-demand in secondary markets. While the Clean Energy Regulator operates a clearing house with a reserve price of $40/STC, to-date prices in secondary markets have been significantly below this level as certificate creation has outstripped liable entities surrender obligations (which are based on ex-ante projections). It has been assumed that forecasts of up-take become more accurate and the STC price trends toward the clearing house level by 2013. This price is held constant to 2030 at $40/STC (nominal).

Similar to the LRET, annual liability under the scheme is enabled through the specification of the Small-scale Technology Percentage (STP). However, unlike **the LRET, the SRES in an uncapped scheme with the 'demand' being** determined by the regulator based on projected certificate creation. It is implicitly assumed that the forecast uptake precisely equals the actual uptake. The STP therefore becomes the projected certificate creation divided by the same relevant acquisitions minus partial exemption certificates as calculated for the LRET.

[4] ACIL Tasman, *Analysis of the impact of the Small Scale Renewable Energy Scheme: Projection of retail electricity price impacts and abatement to 2020*, November 2011

3 Base case

The 'Base case' scenario is based primarily on ACIL Tasman views in consultation with TRUenergy. It is used as a reference point for the status quo.

3.1 Scenario design and key inputs

The key inputs to the Base case scenario are:

- Peak demand and energy projections as per AEMO's recent National Electricity Forecasting Report with some minor adjustments to account for additional LNG-based load in Queensland (approximately 600 MW above the AEMO forecast).
- Fuel cost projections as per ACIL Tasman internal Base case views. This includes gas market modelling which has a total of eight LNG trains developed in Queensland, with domestic prices trending toward LNG netback.
- Carbon prices which utilise the fixed prices under the current Clean Energy Future legislation until 30 June 2015, then move onto a floating price under the ETS. ACIL Tasman has used the mid-point between prices forecast by Treasury under its Core Policy case and an extrapolated CER forward curve. These carbon prices are detailed in Table 1.[5]
- New entrant costs and technical parameters are per ACIL Tasman's internal database.
- The Contract for Closure (CFC) mechanism is assumed to result in the closure of the Energy Brix (195 MW) coal-fired power station in 2021. Playford is assumed to remain closed. No other stations were assumed to close under the CFC or retired on economic grounds.

Table 1 **Carbon prices assumed: Base case**

Financial Year	Base case	Core Policy	CER Forward
2012-13	23.00	23.00	5.19
2013-14	24.15	24.15	5.47
2014-15	25.40	25.40	6.05
2015-16	17.69	28.86	6.52
2016-17	18.85	30.81	6.89
2017-18	20.16	33.06	7.25
2018-19	21.53	35.40	7.65
2019-20	23.16	38.10	8.23
2020-21	25.02	41.31	8.72

[5] We note the recently announced linkage with the European emissions trading scheme from 1 July 2015.

Financial Year	Base case	Core Policy	CER Forward
2021-22	27.09	44.93	9.24
2022-23	29.32	48.85	9.80
2023-24	31.73	53.07	10.39
2024-25	34.39	57.77	11.01
2025-26	37.25	62.82	11.67
2026-27	40.31	68.24	12.37
2027-28	43.58	74.05	13.11
2028-29	47.33	80.76	13.90
2029-30	51.00	87.26	14.73

Note: Nominal $/tonne CO_2-e

Data source: Commonwealth Treasury (Core Policy), ICE CER Forward Curve (9 July 2012) and ACIL Tasman analysis

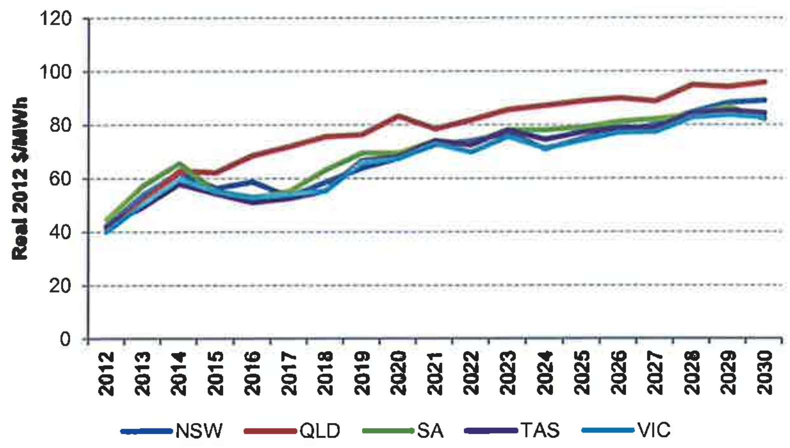
3.2 Wholesale market results

3.2.1 NEM outcomes

Figure 2 and Table 2 provide the time-weighted annual average pool price outcomes under the Base case NEM modelling. Key points from price projection are as follows:

- Wholesale prices are projected to rise strongly driven by carbon prices and increasing gas costs over the longer term.
- Prices moderate in most regions in 2016 due to the drop in carbon prices assumed in all regions except Queensland where rapid demand growth occurs stemming from CSG-LNG loads coming online.
- Development of large quantities of wind generation in the period 2014 to 2018, combined with low demand growth tend to suppress wholesale price outcomes below new entry levels in Southern States.
- In the longer-term Queensland exhibits the highest wholesale prices, due to higher wholesale gas prices.

Figure 2 **Projected NEM pool price outcomes: Base case**



Note: Time-weighted average annual prices. Year 2012 includes actual market price outcomes from January to June. Real 2012 $/MWh

Data source: ACIL Tasman PowerMark modelling, AEMO

Table 2 **Projected NEM pool price outcomes: Base case**

Calendar year	NSW	QLD	SA	TAS	VIC
2012	42.07	41.19	44.59	42.35	40.12
2013	53.99	51.57	57.38	49.48	50.51
2014	62.28	62.80	65.61	58.08	59.96
2015	56.32	62.28	55.19	54.50	55.36
2016	58.76	68.54	52.75	51.06	52.93
2017	53.22	71.91	55.08	52.60	54.27
2018	58.65	75.72	63.24	55.44	55.22
2019	63.96	76.41	69.45	66.65	66.13
2020	67.57	83.32	69.45	67.98	67.40
2021	72.68	78.54	74.00	74.10	72.88
2022	73.97	81.87	72.85	72.48	69.81
2023	76.79	85.76	78.04	78.17	75.60
2024	70.96	87.33	78.06	74.50	71.28
2025	74.75	89.01	79.12	77.33	74.26
2026	77.70	90.00	81.17	79.11	77.15
2027	80.04	88.90	82.13	79.04	77.39
2028	84.84	95.05	83.87	84.42	82.69
2029	88.29	94.21	86.68	85.37	83.71
2030	89.11	95.87	82.06	84.42	82.70
Compound growth rates (Real)					
2012 to 2020	6.1%	9.2%	5.7%	6.1%	6.7%
2020 to 2030	2.8%	1.4%	1.7%	2.2%	2.1%
2012 to 2030	4.3%	4.8%	3.4%	3.9%	4.1%

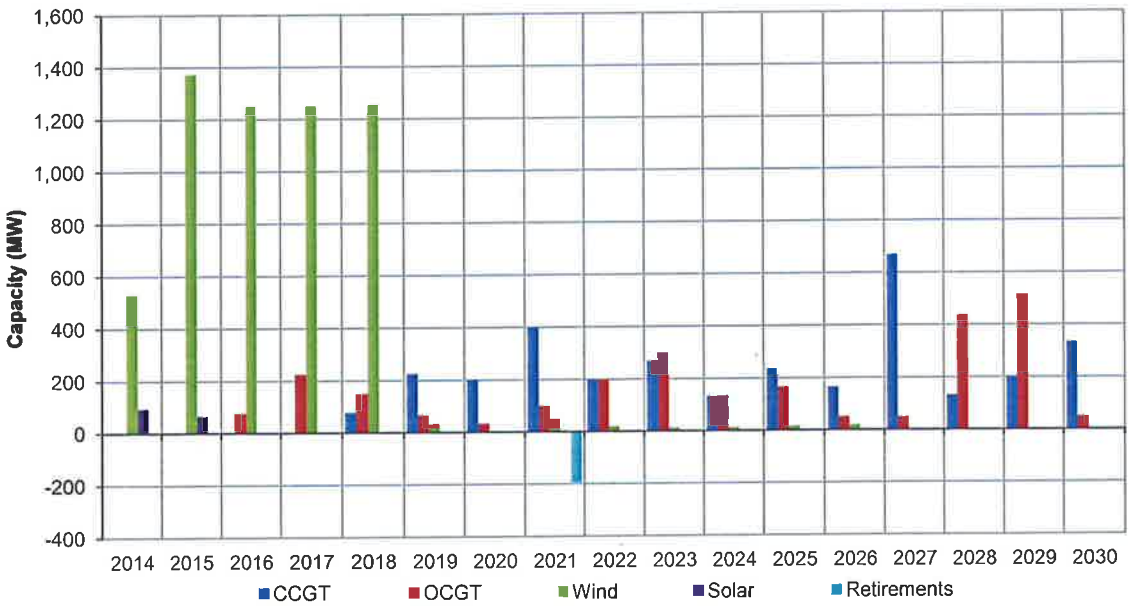
Note: Time-weighted average annual prices. Year 2012 includes actual market price outcomes from January to June. Real 2012 $/MWh

Data source: ACIL Tasman PowerMark modelling, AEMO

Figure 3 shows the new entrant and retirement profiles under the Base case for gas-fired technologies, wind, solar and incumbent power station retirements. New wind development dominates the early years of the projection, driven by the LRET subsidy. This defers the need for gas-fired generation until late in the decade.

Much of this new generation development occurs in Queensland where demand growth is the strongest of all NEM regions.

Figure 3 **NEM new entrant and retirement profile: Base case**



Note: New entrant plant introduced midway through the year will show a proportion of the total capacity in that year, with the balance in the following year.
Data source: ACIL Tasman PowerMark modelling

3.2.2 LRET outcomes

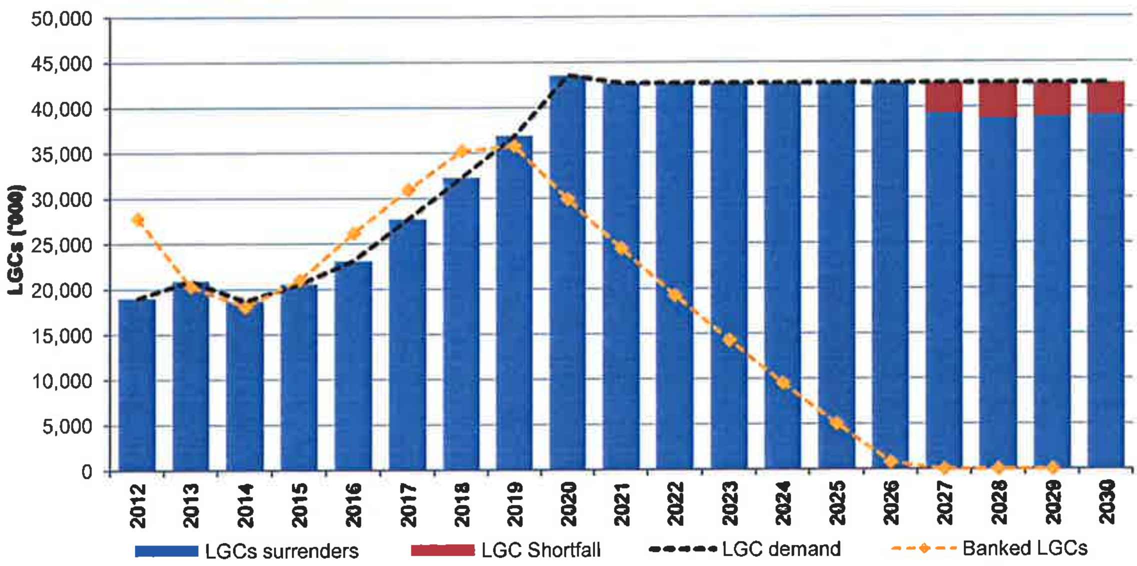
Figure 4 shows the LGC demand and annual surrenders under the scheme. New renewable developments are sufficient to meet liable entity obligations until 2027 when a shortfall against the target occurs. This implies that it is cheaper for liable entities to pay the penalty rather than pay the required subsidy for incremental renewable generation.

Figure 5 shows the aggregate LGCs created by technology and by jurisdiction over the period 2012 to 2030. In total 620 million LGCs are created which includes contributions from already existing stations.

Wind dominates new renewable development accounting for virtually all new large-scale deployment. No geothermal or utility scale solar plants (aside from those partially funded through solar flagships) are projected to be built within the modelling.

Figure 6 shows the projected LGCs price path under the Base case. As the market experiences a certificate shortfall from 2027 onward, the projected price reflects the tax-adjusted penalty price in this period.[6] The model projects **a "Hotelling" type price path, where current prices at linked to the marginal** 2027 price by the assumed holding cost interest rate. This gives a current projected 2012 LGC price of around $30.80/certificate.

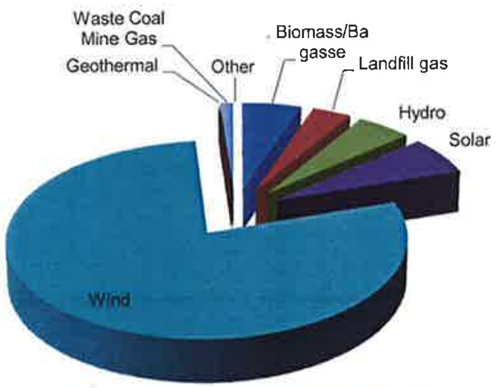
Figure 4 **LGC surrenders and banked LGCs 2012-2030: Base case**



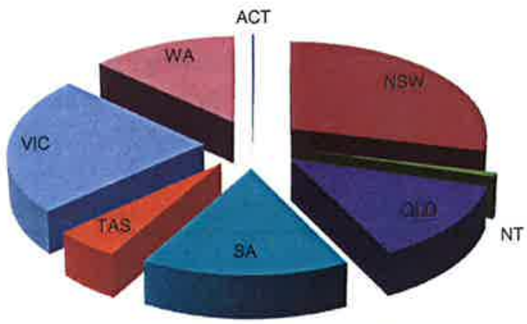
Note: **Surrendered include those to acquit obligations and voluntary surrenders. Banked LGCs are presented after that year's surrender** has occurred.
Data source: ACIL Tasman RECMark modelling

[6] It should be noted that the tax-adjusted penalty price of $92.86/LGC has been used, but it is acknowledged that liable entities may pay higher prices to avoid a shortfall and the associated potential reputational damage that may accompany such an outcome.

Figure 5 **LGCs created by fuel source and by jurisdiction: Base case**



Fuel type	LGCs (million)	Share
Biomass/Bagasse	32.9	5.3%
Landfill gas	21.7	3.5%
Hydro	30.6	4.9%
Solar	39.2	6.3%
Wind	488.4	78.8%
Geothermal	0.0	0.0%
Waste Coal Mine Gas	7.3	1.2%
Other	0.0	0.0%
	620.0	100.0%

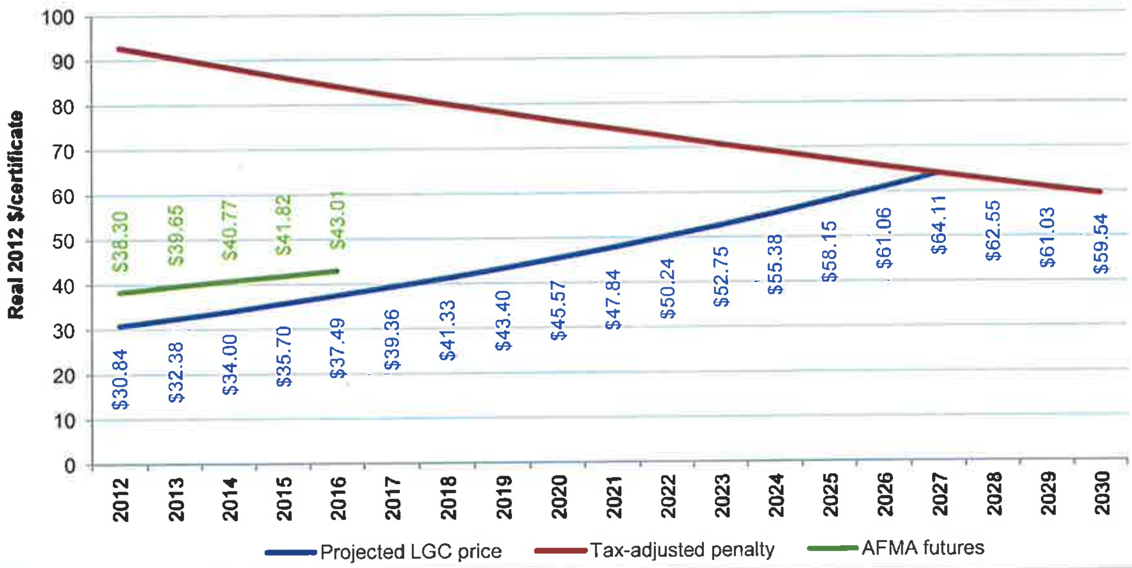


Jurisdiction	LGCs (million)	Share
ACT	0.9	0.1%
NSW	178.3	28.8%
NT	4.5	0.7%
QLD	81.0	13.1%
SA	97.7	15.8%
TAS	31.5	5.1%
VIC	144.9	23.4%
WA	81.2	13.1%
Total	620.0	100.0%

Note: Aggregate projected LGCs created 2012 to 2030. Includes LGCs created from existing accredited generators.

Data source: ACIL Tasman RECMark modelling

Figure 6 **Projected LGC prices and current futures prices: Base case**



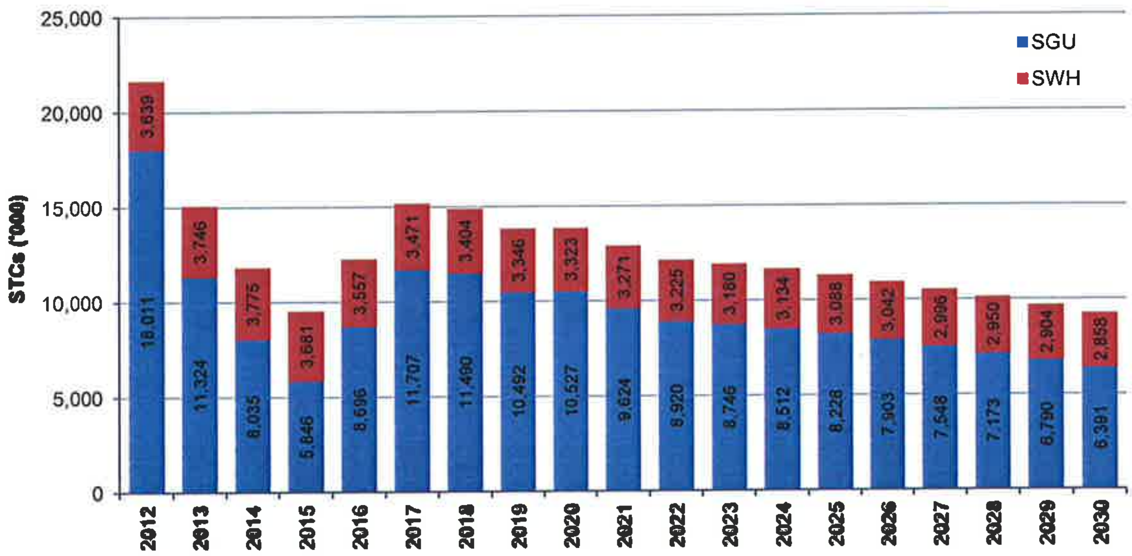
Note: AFMA futures prices are mean of all mids as at 9 August 2012, converted to Real 2012 dollars. Inflation of 2.5% used throughout. Timing of AFMA prices have not been adjusted to match RECMark timing (i.e. AFMA Cal12 is for delivery in Jan 2013; whereas RECMark 2012 price applies throughout calendar year 2012).

Data source: ACIL Tasman RECMark modelling, AFMA

3.2.3 SRES outcomes

STC creation is driven by the assumptions on PV installs (which are derived from the AEMO forecasts) and SWH uptake as shown below.

Figure 7 **Projected STC creation rates by technology: Base case**



Note: The STP for the 2012 year is 23.96% (equivalent to 44.786 million in 2012). This includes carry-over of some 23 million excess certificates from 2011. STC acquittal estimates for 2013 and 2014 have been based from the Clean Energy Regulator's non-binding estimates which were set on 30 March 2012.
Data source: ACIL Tasman analysis

Table 3 **Summary of SRES projections: Base case**

Calendar year	Relevant acquisitions	PECs	Reduced acquisitions	STC acquittal target	Projected STP	STC price
	GWh	GWh	GWh	('000)	%	$/STC
2012	210,989	28,860	182,129	44,786	23.96%	$33.65
2013	216,645	25,176	191,469	15,070	7.87%	$40.00
2014	224,232	22,858	201,374	11,810	5.86%	$40.00
2015	230,189	22,070	208,119	9,527	4.58%	$40.00
2016	234,672	22,994	211,679	12,254	5.79%	$40.00
2017	238,296	23,701	214,596	15,178	7.07%	$40.00
2018	241,108	23,559	217,548	14,894	6.85%	$40.00
2019	244,277	24,442	219,835	13,838	6.29%	$40.00
2020	247,563	25,520	222,043	13,850	6.24%	$40.00
2021	250,064	25,758	224,306	12,896	5.75%	$40.00
2022	252,201	26,025	226,176	12,146	5.37%	$40.00
2023	254,785	26,373	228,412	11,925	5.22%	$40.00
2024	257,867	26,772	231,095	11,646	5.04%	$40.00
2025	261,064	27,177	233,887	11,316	4.84%	$40.00
2026	264,158	27,568	236,590	10,945	4.63%	$40.00

Calendar year	Relevant acquisitions	PECs	Reduced acquisitions	STC acquittal target	Projected STP	STC price
	GWh	GWh	GWh	('000)	%	$/STC
2027	266,978	27,920	239,058	10,544	4.41%	$40.00
2028	269,194	28,200	240,994	10,123	4.20%	$40.00
2029	271,233	27,250	243,983	9,694	3.97%	$40.00
2030	273,421	26,303	247,118	9,250	3.74%	$40.00

Note: STC acquittal estimates for 2013 and 2014 have been based from the Clean Energy Regulator's non-binding estimates which were set on 30 March 2012.
Data source: ACIL Tasman analysis

3.3 Summary of RET costs

In aggregate over the period 2012 to 2030, the total subsidy projected to be paid under the LRET/SRES is around $53.3 billion in nominal terms as detailed in Table 4. Around 81% of this total ($43.1 billion) is associated with the LRET.

Table 4 **RET cost summary: Base case**

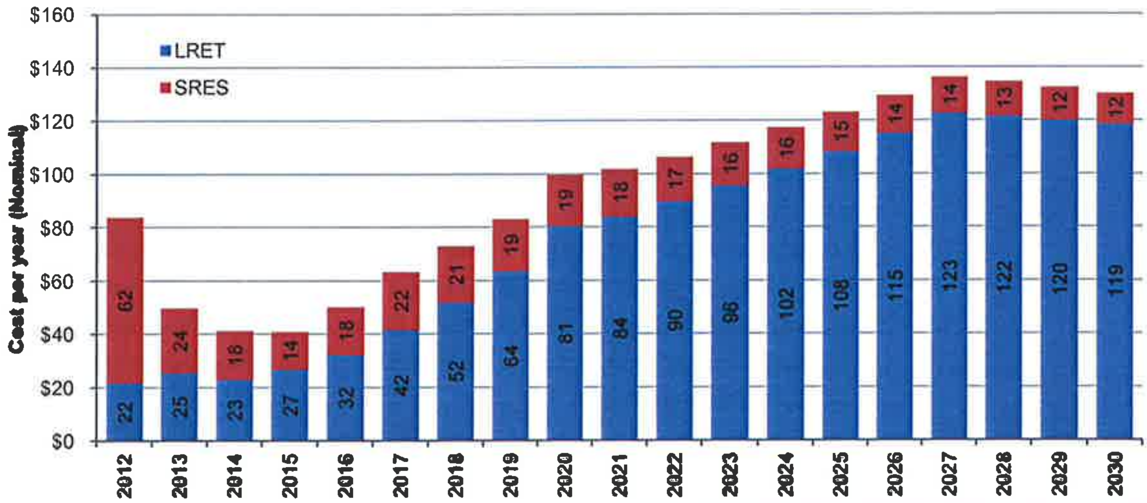
Calendar year	Relevant acquisitions	PECs	Reduced acquisitions	Projected RPP	Projected STP	LRET cost	SRES cost	Total RET cost
	GWh	GWh	GWh	%	%	$m	$m	$m
2012	210,989	28,860	182,129	9.15%	23.96%	514	1,469	1,983
2013	216,645	25,176	191,469	9.97%	7.87%	634	603	1,236
2014	224,232	22,858	201,374	8.42%	5.86%	605	472	1,078
2015	230,189	22,070	208,119	9.06%	4.58%	725	381	1,106
2016	234,672	22,994	211,679	10.12%	5.79%	887	490	1,377
2017	238,296	23,701	214,596	12.13%	7.07%	1,159	607	1,766
2018	241,108	23,559	217,548	14.08%	6.85%	1,468	596	2,064
2019	244,277	24,442	219,835	16.03%	6.29%	1,817	554	2,371
2020	247,563	25,520	222,043	18.85%	6.24%	2,323	554	2,877
2021	250,064	25,758	224,306	18.28%	5.75%	2,450	516	2,966
2022	252,201	26,025	226,176	18.13%	5.37%	2,637	486	3,122
2023	254,785	26,373	228,412	17.95%	5.22%	2,838	477	3,315
2024	257,867	26,772	231,095	17.74%	5.04%	3,054	466	3,520
2025	261,064	27,177	233,887	17.53%	4.84%	3,287	453	3,739
2026	264,158	27,568	236,590	17.33%	4.63%	3,537	438	3,975
2027	266,978	27,920	239,058	17.15%	4.41%	3,807	422	4,229
2028	269,194	28,200	240,994	17.01%	4.20%	3,807	405	4,212
2029	271,233	27,250	243,983	16.80%	3.97%	3,807	388	4,195
2030	273,421	26,303	247,118	16.59%	3.74%	3,807	370	4,177
Total						43,163	10,145	53,308

Note: Nominal dollars. PECs = Partial exemption certificates; RPP = Renewable Power Percentage under LRET; STP = Small-scale Technology Percentage under SRES
Data source: ACIL Tasman projections

Figure 8 presents the annual costs from the policies for a typical residential household consuming 7 MWh per annum. Costs in 2012 are estimated to be around $88/year. This is expected to fall over coming years as the STP declines – primarily a result of the declining Solar Credits multiplier for solar PV systems.

LRET is projected to be a much larger cost upon households, with costs projected to increase from around $22/year currently to $123/year by 2027 in nominal terms.

Figure 8 **Indicative annual individual household cost: Base case**



Note: Based on household consumption of7 MWh per year; includes 10% notional energy losses; excludes GST. Nominal dollars based on assumed inflation of 2.5%

Data source: ACIL Tasman estimates

4 'Real 20%' LRET

There have been a number of calls for a revision to the LRET targets which are currently specified in fixed GWh terms. This is in light of the large reductions in anticipated demand relative to what was expected when the original Expanded Renewable Energy Target was announced in 2007.

This scenario seeks to examine the impact of a lower aggregate target for LRET which is based on 20% of the current expected level of energy consumed in 2020.

4.1 Scenario design and key inputs

Table 5 presents the derivation of the 'Real 20%' LRET target level. Herein we have used the projected 'Relevant Acquisition' measure[7] under the legislation as the appropriate measure of Australia energy in 2020. A revised 'Real 20%' target takes this projected amount (49,513 GWh) and subtracts existing baselined energy of 16,584 GWh and the original SRES energy allowance of 4,000 GWh to give a revised 2020 target of 28,929 GWh. We have held the existing target values to 2016 constant in the interests of near-term certainty, and then straight-lined interim targets to the 2020 value and held constant (in GWh terms) thereafter.

These figures are shown graphically and compared with the existing LRET targets in Figure 9.

Table 5 **Revised 'Real 20%' target for the LRET**

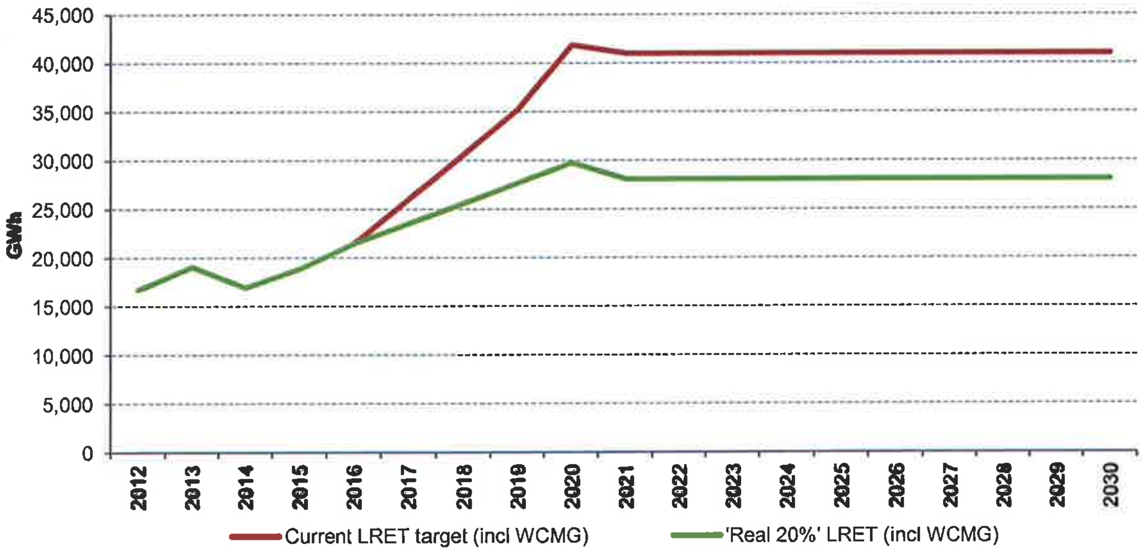
	Relevant acquisitions	2020 20% target	Less existing baselined energy	Allowance for SRES energy (as originally anticipated)	'Real 20%' LRET (excl WCMG)	WCMG	'Real 20%' LRET (incl WCMG)
	GWh	GWh	GWh	GWh	GWh	GWh	GWh
2012	210,989				16,338	425	16,763
2013	216,645				18,238	850	19,088
2014	224,232				16,100	850	16,950
2015	230,189				18,000	850	18,850
2016	234,672				20,581	850	21,431
2017	238,296				22,668	850	23,518
2018	241,108				24,755	850	25,605
2019	244,277				26,842	850	27,692
2020	247,563	49,513	16,584	4,000	28,929	850	29,779

[7] It should be noted that this measure excludes self-generation and off/small grid electricity consumption.

	Relevant acquisitions	2020 20% target	Less existing baselined energy	Allowance for SRES energy (as originally anticipated)	'Real 20%' LRET (excl WCMG)	WCMG	'Real 20%' LRET (incl WCMG)
	GWh	GWh	GWh	GWh	GWh	GWh	GWh
2021	250,064				28,079	0	28,079
2022	252,201				28,079	0	28,079
2023	254,785				28,079	0	28,079
2024	257,867				28,079	0	28,079
2025	261,064				28,079	0	28,079
2026	264,158				28,079	0	28,079
2027	266,978				28,079	0	28,079
2028	269,194				28,079	0	28,079
2029	271,233				28,079	0	28,079
2030	273,421				28,079	0	28,079

Note: WCMG = Waste Coal Mine Gas. Targets for 2012 to 2016 left unchanged in the interests of near-term certainty
Data source: ACIL Tasman analysis

Figure 9 **Revised 'Real 20%' target for the LRET compared with currently legislated target**



Data source: ACIL Tasman analysis

4.2 Wholesale market results

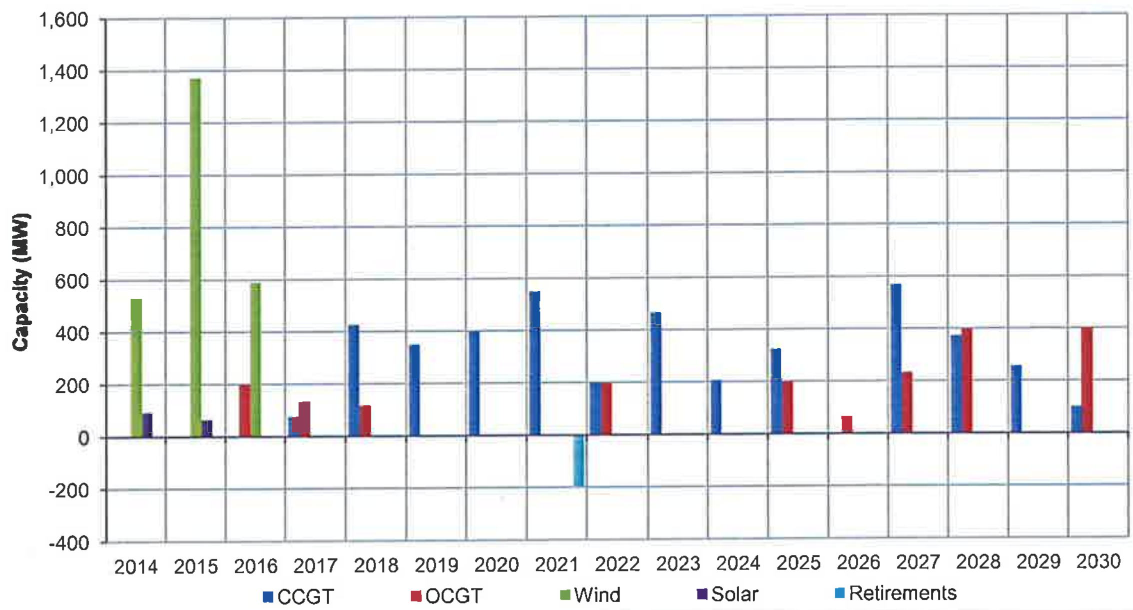
4.2.1 NEM outcomes

Generally NEM wholesale prices are marginally higher in the period to 2020 as a result of the lower level of wind development. While the new entrant schedule has been adjusted accordingly, prices in some regions remain below levels which would make new entrants economic in the period to 2020. In these periods, the reduction in wind development results in higher wholesale price outcomes.

The new entrant profile is somewhat different under this scenario relative to the Base case. Capacity differences in the NEM throughout the period include:

- 3,300 MW less wind
- 600 MW less OCGT capacity
- 1,000 MW more CCGT capacity.

Figure 10 **NEM new entrant and retirement profile: 'Real 20%' scenario**



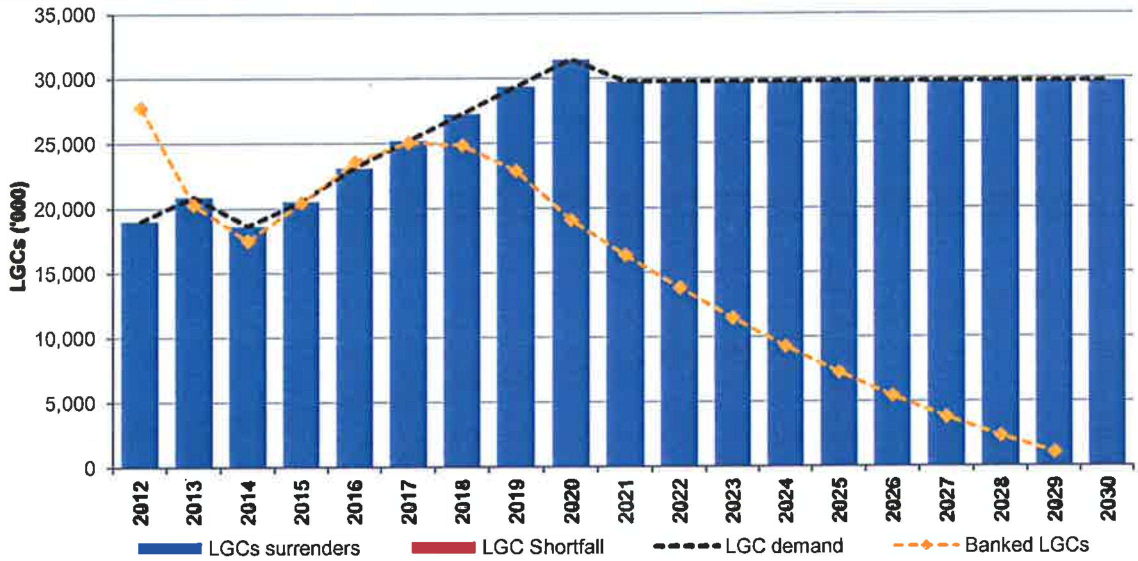
Note: New entrant plant introduced midway through the year will show a proportion of the total capacity in that year, with the balance in the following year.
Data source: ACIL Tasman PowerMark modelling

4.2.2 LRET outcomes

The lower LRET target results in the scheme being fully subscribed throughout as shown in Figure 11. The amount of LGCs banked peaks at around 25 million in 2017 and is gradually drawn down over the period to 2030. This indicates that annual LGC creation from renewable plants is slightly less than the targets from 2019 onwards. Reflecting the perfect foresight assumption employed by the model, the bank is fully drawn down in the final year of the scheme.

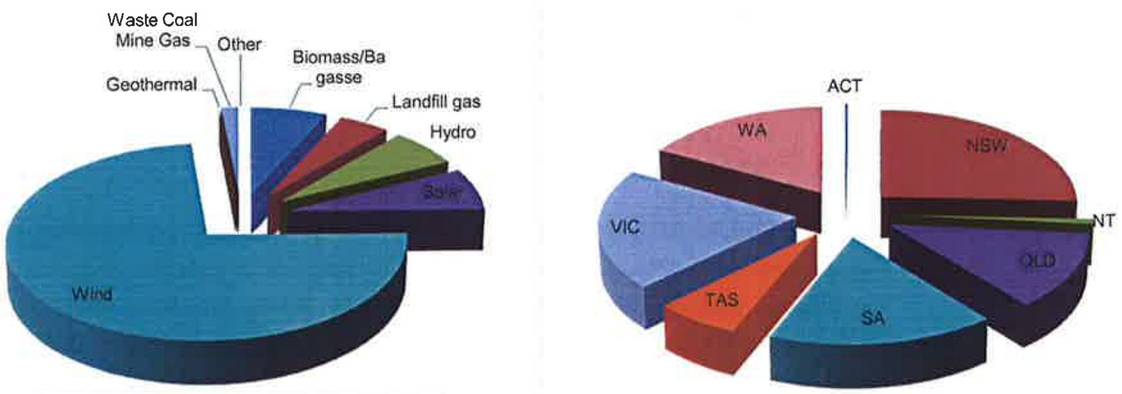
Aggregate LGCs created over the period 2012 to 2030 is around 478 million (620 million under the Base case) as detailed in Figure 12.

Figure 11 **LGC surrenders and banked LGCs 2012-2030: 'Real 20%' scenario**



Note: Surrendered include those to acquit obligations and voluntary surrenders. Banked LGCs are presented after that year's surrender has occurred.
Data source: ACIL Tasman RECMark modelling

Figure 12 **LGCs created by fuel source and by jurisdiction: 'Real 20%' scenario**



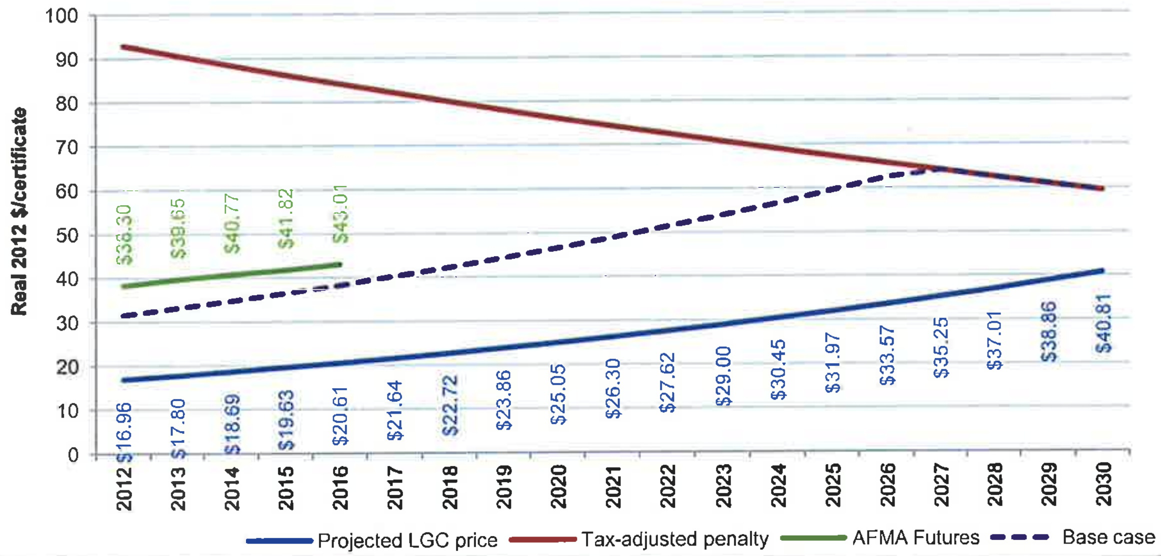
Fuel type	LGCs (million)	Share
Biomass/Bagasse	32.9	6.9%
Landfill gas	21.7	4.5%
Hydro	30.6	6.4%
Solar	33.8	7.1%
Wind	351.9	73.6%
Geothermal	0.0	0.0%
Waste Coal Mine Gas	7.3	1.5%
Other	0.0	0.0%
	478.1	100.0%

Jurisdiction	LGCs (million)	Share
ACT	0.9	0.2%
NSW	122.6	25.6%
NT	3.9	0.8%
QLD	60.3	12.6%
SA	81.7	17.1%
TAS	31.5	6.6%
VIC	96.6	20.2%
WA	80.6	16.9%
Total	478.1	100.0%

Note: Aggregate projected LGCs created 2012 to 2030. Includes LGCs created from existing accredited generators.
Data source: ACIL Tasman RECMark modelling

Reflecting the lower target, LGC prices are much lower at around $17/certificate in 2012, escalating at the assumed holding cost (5% real). This is around $20 below the current futures price for 2012 LGCs. If this change to the target was announced, spot prices would immediately adjust downwards based on the revised outlook.

Figure 13 **Projected LGC prices and current futures prices: 'Real 20%' scenario**



Note: AFMA futures prices are mean of all mids as at 9 August 2012, converted to Real 2012 dollars. Inflation of 2.5% used throughout. Timing of AFMA prices have not been adjusted to match RECMark timing (i.e. AFMA Cal12 is for delivery in Jan 2013; whereas RECMark 2012 price applies throughout calendar year 2012).
Data source: ACIL Tasman RECMark modelling, AFMA

4.2.3 SRES outcomes

Up-take under SRES are identical to those within the Base case however there are some feedback loops associated with the amount of partial exemption certificates such that the STP will differ slightly. As the number of PECs issued is dependent upon the aggregate cost of the RET compared with the original MRET, fewer PECs will be issued under this scenario. This therefore reduces the cost of SRES to non-exempt liable loads although the difference compared with the Base case is largely immaterial.

4.3 Aggregate RET costs

The adjustment to the LRET target to account for the lower anticipated 2020 demand level results in the overall subsidy falling to around $28 billion over the period in nominal terms (a $25.2 billion reduction from the Base case) as detailed in Table 6. The RPP peaks at around five percentage points lower in 2020 (13.3% compared with 18.8% in the Base case).

Table 6 **RET cost summary: 'Real 20%' scenario**

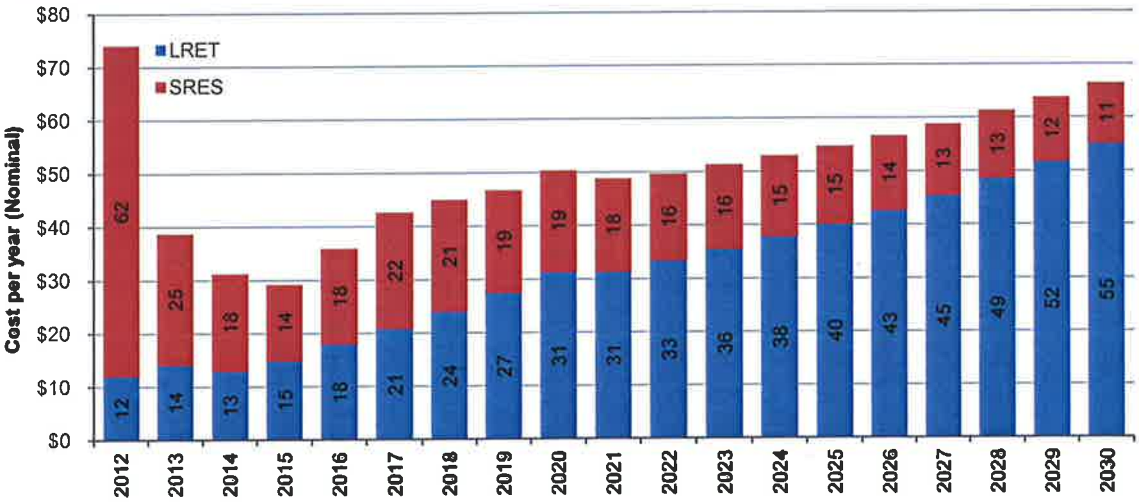
Calendar year	Relevant acquisitions	PECs	Reduced acquisitions	Projected RPP	Projected STP	LRET cost	SRES cost	Total RET cost
	GWh	GWh	GWh	%	%	$m	$m	$m
2012	210,989	28,860	182,129	9.15%	23.96%	283	1,469	1,751
2013	216,645	27,581	189,065	10.10%	7.97%	348	603	951
2014	224,232	25,582	198,649	8.53%	5.95%	333	472	805
2015	230,189	24,462	205,727	9.16%	4.63%	398	381	780
2016	234,672	25,065	209,608	10.22%	5.85%	488	490	978
2017	238,296	24,815	213,482	11.02%	7.11%	576	607	1,183
2018	241,108	23,666	217,442	11.78%	6.85%	675	596	1,270
2019	244,277	23,688	220,589	12.55%	6.27%	785	554	1,339
2020	247,563	23,960	223,603	13.32%	6.19%	909	554	1,463
2021	250,064	23,519	226,546	12.39%	5.69%	922	516	1,438
2022	252,201	23,270	228,932	12.27%	5.31%	993	486	1,479
2023	254,785	23,174	231,611	12.12%	5.15%	1,068	477	1,545
2024	257,867	23,125	234,743	11.96%	4.96%	1,150	466	1,616
2025	261,064	23,252	237,811	11.81%	4.76%	1,238	453	1,690
2026	264,158	23,736	240,421	11.68%	4.55%	1,332	438	1,770
2027	266,978	24,192	242,786	11.57%	4.34%	1,433	422	1,855
2028	269,194	24,589	244,605	11.48%	4.14%	1,543	405	1,948
2029	271,233	24,067	247,166	11.36%	3.92%	1,660	388	2,048
2030	273,421	23,520	249,901	11.24%	3.70%	1,787	370	2,157
Total						17,921	10,145	28,066

Note: Nominal dollars. PECs = Partial exemption certificates; RPP = Renewable Power Percentage under LRET; STP = Small-scale Technology Percentage under SRES

Data source: ACIL Tasman projections

The lower RPP combined with the lower projected LGC prices combine to lower the effective cost of the scheme upon households as shown in Figure 14. Total cost of the RET policy in 2020 to an average household is around $50/year, compared with around $100/year under the Base case.

Figure 14 **Indicative annual individual household cost: 'Real 20%' scenario**



Note: Based on household consumption of7 MWh per year; includes 10% notional energy losses; excludes GST. Nominal dollars based on assumed inflation of 2.5%

Data source: ACIL Tasman estimates

5 Comparisons of scenarios

The RET in its current form is a significant subsidy with an estimated total direct value of $53.3 billion within the Base case as shown in Table 7. Over 80% of this is associated with the LRET, where costs are anticipated to grow over time, in line with increasing fixed GWh targets. The direct costs of subsidising small-scale systems, whilst currently high due to the influence of Solar Credits multiplier, is projected to decrease over time.

The 'Real 20%' scenario which lowers the fixed 2020 GWh targets in accordance with the current demand outlook reduces the aggregate direct cost to $28.1 billion ($25.2 billion lower than the Base case). This adjustment results in the 2020 target falling to around 28,000 GWh compared with the current 41,000 GWh level. The lower target results in lower certificate prices, and a lower level of large-scale renewable deployment (wind in the NEM is around 3,300 MW lower by 2020 under this scenario).

Table 7 **Projected aggregate subsidies paid through RET**

Scenario	Aggregate LRET subsidy 2012-2030	Aggregate SRES subsidy 2012-2030	Aggregate RET subsidy 2012-2030
	$ billion	$ billion	$ billion
Base case	43.2	10.1	53.3
'Real 20%' LRET	17.9	10.1	28.1

Note: Nominal dollars.
Data source: ACIL Tasman projections

Modifications to the RET will have some short-term impacts upon wholesale electricity price outcomes. Policy changes which increase renewable development (at the margin) in the NEM will tend to depress wholesale electricity prices. Conversely, policy changes which reduce the amount of renewable development will tend to increase wholesale electricity prices. However, these effects will be small and the amount and timing of new entrant fossil fuelled capacity will adjust accordingly such that the wholesale market will not deviate from its equilibrium price path.[8] Owing to the lumpy nature of generation investment, in most cases the influence of RET policy changes upon modelled wholesale market outcomes, once new entry levels have been reached, can be characterised as modelling noise.

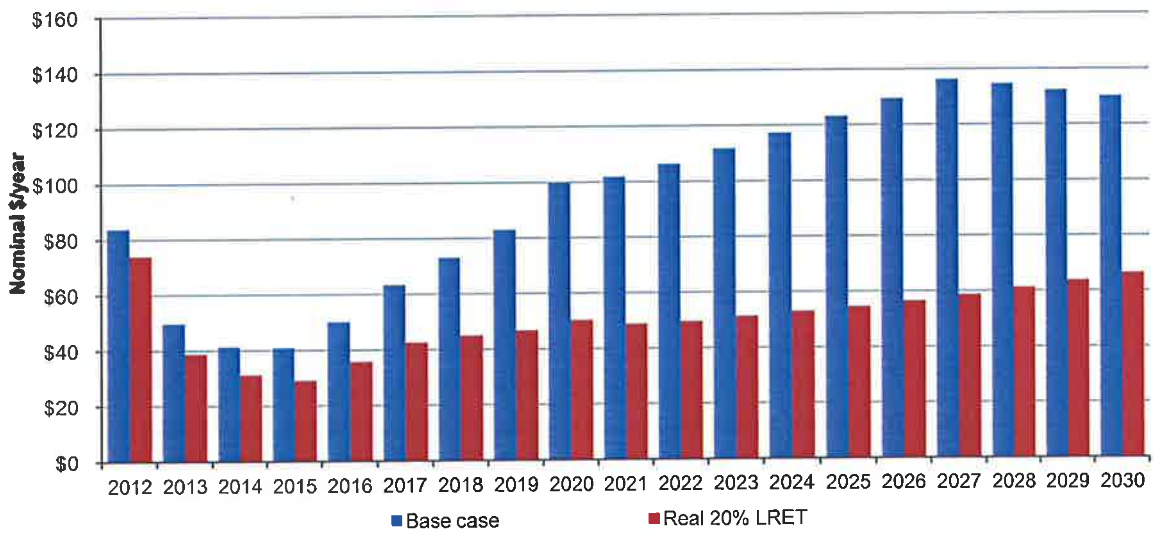
[8] **Provided the RET policy settings doesn't result in a permanent change to the marginal new** entrant technology.

Figure 15 compares the estimated individual household direct cost of the LRET/SRES under the various scenarios examined. The total cost under the Base case is estimated to be around $80/year in 2012 and projected to fall to around half this value by 2014. This then rises to peak at just under $140/year by 2027. Note that this does not include the shortfall payments which would be made in the period 2027 to 2030.

The 'Real 20%' LRET results in a dramatic reduction in direct costs to residential electricity consumers with immediate effects through lower certificate prices and lower RPP values from 2016 onwards. The aggregate cost in 2020 for a household under this scenario is around half that projected within the Base case.

In summary, the total direct cost upon households from the RET scheme under each scenario over the period 2012 to 2030 (in nominal terms) is $1,800 under the Base case **and only $960 under the 'Real 20%' scenario.**

Figure 15 **Indicative annual individual household cost of RET: Scenario comparison**



Note: Based on household consumption of7 MWh per year; includes 10% notional energy losses; excludes GST. Nominal dollars based on assumed inflation of 2.5%. Includes both LRET and SRES costs

Data source: ACIL Tasman estimates

Melbourne (Head Office)
Level 4, 114 William Street
Melbourne VIC 3000

Telephone (+61 3) 9604 4400
Facsimile (+61 3) 9604 4455
Email melbourne@aciltasman.com.au

Brisbane
Level 15, 127 Creek Street
Brisbane QLD 4000
GPO Box 32
Brisbane QLD 4001

Telephone (+61 7) 3009 8700
Facsimile (+61 7) 3009 8799
Email brisbane@aciltasman.com.au

Canberra
Level 2, 33 Ainslie Place
Canberra City ACT 2600
GPO Box 1322
Canberra ACT 2601

Telephone (+61 2) 6103 8200
Facsimile (+61 2) 6103 8233
Email canberra@aciltasman.com.au

Perth
Centa Building C2, 118 Railway Street
West Perth WA 6005

Telephone (+61 8) 9449 9600
Facsimile (+61 8) 9322 3955
Email perth@aciltasman.com.au

Sydney
Level 20, Tower 2 Darling Park
201 Sussex Street
Sydney NSW 2000
GPO Box 4670
Sydney NSW 2001

Telephone (+61 2) 9389 7842
Facsimile (+61 2) 8080 8142
Email sydney@aciltasman.com.au

ACIL Tasman

Economics Policy Strategy

www.aciltasman.com.au